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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Compliance Review of Utility Owned Generation Operations, Electric Energy Resource Recovery Account Entries, Contract Administration, Economic Dispatch of Electric Resources, Utility Retained Generation Fuel Procurement, and Other Activities for the Period January 1 through December 31, 2012 (U 39 E)	Application 13-02-023

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) OPENING BRIEF

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SUMMARY OF RECOMMENDATIONS

Pursuant to California Public Utilities Commission Rule 13.11, Pacific Gas and Electric Company ("PG&E") provides the following summary of its recommendations. PG&E's recommendations are based on the relief requested in its Application and the issues identified in the *Scoping Memo and Ruling of Assigned Commissioner* issued in this proceeding on October 4, 2013 ("Scoping Memo"). PG&E requests that the Commission issue a decision that makes the following findings:

1. During the record period, PG&E administered and managed its utility-owned generation ("UOG") facilities prudently, consistent with the reasonable manager standard, including outages at UOG facilities and associated fuel costs;
2. During the record period, PG&E prudently administered its Qualifying Facility ("QF") and non-QF contracts in accordance with the contract provisions;
3. The transactions, generally contract amendments, identified in Table 10-22 of Exhibit PG&E-1 are reasonable and any costs associated with these amendments should be recovered through the Energy Resource Recovery Account ("ERRA");
4. During the record period, PG&E achieved least-cost dispatch of its energy resources;
5. During the record period, PG&E's fuel procurement for UOG and contracted resources complied with PG&E's Bundled Procurement Plan;
6. During the record period, PG&E made appropriate and reasonable entries to the ERRA balancing account;
7. The costs booked to the Market Redesign and Technology Upgrade Memorandum Account ("MRTUMA") are reasonable and PG&E has met its burden of proof

regarding its claim for recovery of these costs. These costs are reflected in Exhibit PG&E-1, Table 15-1;

8. The costs booked to the Diablo Canyon Seismic Studies Balancing Account ("DCSSBA") are reasonable and PG&E has met its burden of proof regarding its claim for recovery of these costs. These costs are reflected in Exhibit PG&E-1, Table 15-2, as corrected by Exhibit PG&E-2;
9. The revenue requirements proposed by PG&E for costs associated with the MRTUMA and DCSSBA in Exhibit PG&E-1,Table 15-3, as corrected by Exhibit PG&E-2, are reasonable and should be collected in rates;
10. During the record period, PG&E's greenhouse gas compliance instrument procurement complied with its Bundled Procurement Plan; and,
11. The forty-eight (48) non-compliant hedging transactions and four (4) offsetting transactions identified in Exhibit PG&E-16 are approved and the net gain from these transactions should be recorded to the ERRA balancing account.

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PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
OPENING BRIEF

Each year, Pacific Gas and Electric Company ("PG&E") submits a compliance review application for its Energy Resource Recovery Account ("ERRA") and for procurement activities related to ERRA. Southern California Edison Company ("SCE") and San Diego Gas and Electric Company ("SDG&E") submit similar annual applications. The ERRA compliance review process is one part of a fundamental restructuring of procurement-related cost recovery that occurred in the aftermath of the 2000-2001 energy crisis and the enactment of Assembly Bill ("AB") 57. Under AB 57, the Commission is charged with reviewing and approving procurement plans for each of the investor-owned utilities ("IOUs"). Once a procurement plan is approved, an IOU is not subject to after-the-fact reasonableness reviews as long as its procurement-related activities are consistent with the plan. In particular, Public Utilities Code Section 454.5(d)(2) provides that an approved procurement plan will:

> Eliminate the need for after-the-fact reasonableness reviews of an electrical corporation's actions in compliance with an approved procurement plan, including resulting electricity procurement contracts, practices, and related expenses. However, the commission may establish a regulatory process to verify and assure that each contract was administered in accordance with the terms of the contract, and contract disputes which may arise are reasonably resolved.

Consistent with this statutory mandate, the Commission established the ERRA compliance application process to review contract administration, least-cost dispatch, and procurement-related activities to verify compliance with an IOU's approved procurement plan.[1]

Since 2003, PG&E and the other IOUs have submitted a number of ERRA compliance applications. Although the scope of issues addressed in these applications has expanded, the fundamental purpose of the ERRA compliance proceeding remains the same. PG&E filed its Application and Prepared Testimony in this proceeding for the 2012 record year on February 28, 2013. PG&E's testimony included detailed descriptions of the operation of its utility-owned generation ("UOG"), least-cost dispatch ("LCD") activities, contract administration, and ERRA balancing account entries. In addition, pursuant to Commission direction, PG&E's Application and Prepared Testimony included information related to costs incurred during the record period for California Independent System Operator ("CAISO") Market Design Initiatives and for Diablo Canyon Nuclear Power Plant ("Diablo Canyon" or "DCPP") seismic studies, as well as cost recovery and ratemaking proposals associated with these costs. PG&E provided detailed workpapers to support its Prepared Testimony.

The only active party in this proceeding has been the Office of Ratepayer Advocates ("ORA"). ORA had a number of witnesses review in detail PG&E's Application and Prepared Testimony, propounded hundreds of discovery requests, and arranged numerous meetings with PG&E witnesses to review PG&E's materials. ORA's review took six months. At the end of this lengthy and detailed review, ORA did not oppose the vast majority of PG&E's request. ORA only challenged three items: (1) three forced outages at UOG facilities; (2) two contract amendments and a settlement agreement; and (3) $3.76 million in costs related to Diablo Canyon seismic studies. With regard to LCD, ORA indicated that it was unable to determine whether

[1] Decision ("D.") 05-04-036 at p. 2 (describing the scope of the first Commission decision reviewing PG&E's ERRA Compliance application).

PG&E achieved LCD each day during the record period, but ORA did not assert that PG&E had not achieved LCD. During the hearings, ORA witnesses generally complimented PG&E's presentation, supporting materials, and the thoroughness of PG&E's ERRA balancing account entries. Given the number of procurement-related activities at issue in this proceeding, the relatively small number of concerns raised by ORA after its intensive review demonstrates the completeness and robustness of PG&E's compliance demonstration.

This proceeding did raise one issue of non-compliance regarding forty-eight (48) hedging transactions that occurred during the record period, and four (4) offsetting transactions entered into in 2013. Notably, PG&E identified and promptly remedied the technical problems that gave rise to the non-compliant transactions, acted quickly to ensure that no loss was incurred as a result of the transactions, established corrective actions to prevent a recurrence of the problem, and is proposing that the $416,122 in net gains be credited to customers. After reviewing the circumstances surrounding these non-complaint transactions and PG&E's subsequent remedial actions, ORA did not recommend a disallowance and now supports corrective actions that are generally consistent with actions proposed by PG&E.

This opening brief reviews all of the substantive issues addressed in PG&E's Application and testimony, as well as the *Scoping Memo and Assigned Commissioner Ruling* ("Scoping Memo") that was issued on October 4, 2013, and demonstrates that each of the recommendations proposed by PG&E at the beginning of this brief should be adopted. PG&E has fully satisfied its burden of proof and provided substantial evidence supporting each of its recommended findings. Consistent with the direction provided by Administrative Law Judge ("ALJ") Roscow, this opening brief follows the organization of PG&E's Prepared Testimony. Sections I and II provide, respectively, the procedural background for this proceeding and the standards of review adopted by the Commission. Sections III to XVI follow the order of PG&E's Prepared Testimony.

I. PROCEDURAL BACKGROUND

PG&E filed its Application and served its Prepared Testimony (Exhibit PG&E-1) on February 28, 2013. In addition to the Prepared Testimony, PG&E also provided responses to ORA's Master Data Requests ("MDR"), which consisted of 128 questions. On March 15, 2013, PG&E provided workpapers to ORA.

In addition to the MDR, ORA propounded numerous additional rounds of discovery and asked for a number of presentations and meetings on specific topics. In total, ORA propounded twenty-eight (28) sets of discovery that included more than 700 individual questions and subparts. ORA also requested, and PG&E arranged, numerous calls and face-to-face meetings on different subjects related to PG&E's Application. For example, PG&E arranged eight meetings or calls on LCD alone.[2] There were also numerous calls and meetings regarding contract administration, outages at specific UOG facilities, demand response, CAISO Market Design Initiatives, and ERRA balancing account entries. Some of these meetings involved lengthy presentations and review of materials. ORA's review of the ERRA balancing account entries lasted for several days and involved a review all the way down to the invoice level.

On August 15, 2013, ALJ Roscow conducted a pre-hearing conference. On August 30, 2013, ORA served its Testimony (Exhibit DRA-1).[3] On September 5, 2013, SCE filed a motion

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[2] Exhibit ("Ex.") PG&E-3 at p. 6-6, Table 6-2. Some of the Exhibits submitted by PG&E and ORA included confidential material. Typically, a confidential and a public version of these exhibits were provided; the confidential exhibit is denoted by a "-C." In this opening brief, if the material cited in a footnote is public, the public version of the exhibit will be cited, for example, Ex. PG&E-1. If the material is confidential, PG&E will cite the confidential version of the exhibit, for example, Ex. PG&E-1-C.

[3] At the time ORA's testimony was submitted, ORA was referred to as the Division of Ratepayer Advocates or "DRA." At the October 7-8, 2013 hearings, ORA's exhibits were marked as Exhibit DRA-1, etc. At the January 21, 2014 hearing, ORA's exhibits were labeled ORA-5, etc. In order to be consistent with the transcript, PG&E will refer to ORA's first four exhibits as DRA-1 through DRA-4, and will refer to ORA's remaining exhibits as ORA-5 through ORA-11.

to intervene that was granted by ALJ Roscow on October 2, 2013. PG&E served its Rebuttal Testimony (Exhibit PG&E-3) on September 27, 2013.

The Scoping Memo was issued on October 4, 2013, bifurcating this proceeding into two phases. Hearings in Phase 1 were conducted on October 7-8, 2013, but did not conclude at that time. PG&E served its Phase 2 testimony on October 14, 2013 and ORA's testimony was served November 22, 2013. PG&E's Phase 2 rebuttal testimony was served December 13, 2013. On January 21, 2014, ALJ Roscow conducted a hearing to conclude Phases 1 and 2. Hearings concluded in the afternoon of January 21 and this matter was deemed submitted.

II. STANDARDS OF REVIEW (EXHIBIT PG&E-1, CHAPTER 1)

There are a number of different issues in this proceeding that have different standards of review. As a preliminary matter, the utility has the burden of proof in ERRA proceedings to demonstrate that its actions were in compliance with its bundled procurement plan.[4] A utility satisfies its burden of proof based on preponderance of the evidence.[5] In addition to the general burden of proof, there are a number of specific standards of review for discrete issues in this proceeding. These standards of review have been described in previous Commission decisions and the Scoping Memo issued in this proceeding.

First, the standard of review for compliance with Standard of Conduct 4 ("SOC4"), specifically with regard to LCD, has evolved over the years and has often varied in past Commission decisions. The various Commission decisions and statements regarding the standard of review for LCD are addressed in more detail below in Section III.A.

Second, with regard to UOG facilities and specifically outages at those facilities, the utilities are held to the reasonable manager standard.[6] Under this standard:

[4] D.05-01-054, Finding of Fact ("FOF") 5; D.11-10-002 at p. 4.

[5] *Id*.

[6] D.11-10-002 at p. 11, n. 2.

> [U]tilities are held to a standard of reasonableness based upon the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision or act.[7]

The reasonable manager standard, as it applies to UOG outages, is described in more detail below in Section IV.[8]

Third, the administration of contracts during a record period is reviewed to determine if the contracts were prudently administered and managed in compliance with the contract provisions.[9]

Fourth, PG&E's application seeks the recovery of certain amounts actually incurred and recorded in the Diablo Canyon Seismic Studies Balancing Account ("DCSSBA") for seismic studies previously approved by the Commission. In D.12-09-008, the Commission directed PG&E to include recovery of these amounts in its ERRA application and to show that these amounts are consistent with PG&E's request in its seismic studies application.[10] The Scoping Memo provided additional guidance, directing that PG&E also demonstrate that the seismic studies costs were reasonably incurred.[11]

Finally, this application also seeks to recover capital and expense costs related to CAISO market initiatives. The Commission previously directed that these costs be included in PG&E's ERRA application and that PG&E demonstrate in its application that the costs are verifiable and

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[7] *Id*.

[8] The Scoping Memo referred to "prudent" management of PG&E's UOG facilities and outages as being an issue within the scope of this proceeding. *See* Scoping Memo at p. 10, Items #1 and #5. PG&E assumes that "prudent management" is the same as the "reasonable manager" standard previously adopted by the Commission.

[9] D.11-07-039 at p. 9; *see also* Scoping Memo at p. 10, Item #2.

[10] D.12-09-008, Ordering Paragraphs ("OP") 4 and 10.

[11] Scoping Memo at p. 8 and p. 10, Item #7.

incremental to the costs recovered in other proceedings.[12] Similar to the Diablo Canyon seismic studies cost, the Scoping Memo also clarified that PG&E also needs to demonstrate that its CAISO market initiative costs were reasonable.[13]

III. LEAST-COST DISPATCH (EXHIBIT PG&E-1, CHAPTER 2)

A. Commission Criteria To Evaluate Least-Cost Dispatch

The Commission's criteria for evaluating LCD compliance has evolved over time in various Commission decisions and has, at times, been less than clear. As the Commission recently explained, a number of its prior decisions addressing LCD compliance have created confusion and an earlier Commission statement that a generic proceeding should take place to establish LCD criteria has not been acted on.[14] This section of PG&E's brief outlines the LCD standards and criteria that the Commission described in prior decisions. Specifically, this section traces the development of the Commission's LCD evaluation criteria and statements that the Commission has made regarding the appropriate demonstration of LCD compliance. These were the standards and criteria in effect at the time that PG&E filed its Application in February 2013, and should be the criteria by which PG&E's LCD showing is evaluated. In Section III.B below, PG&E reviews the showing that it made in this proceeding regarding LCD and explains how this showing demonstrated LCD compliance for the Record Period.

1. Compliance With Standard of Conduct 4 And A Utility's Approved Procurement Plan Are The Basis For LCD Review

When the utilities resumed their procurement role after the 2000-2001 energy crisis and the passage of AB 57, the Commission adopted SOC 4 as the standard for both contract administration and LCD.[15] SOC 4 provides:

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[12] D.09-12-021 at p. 3, n. 1; D.11-07-039 at pp. 18-19.

[13] Scoping Memo at pp. 7-8 and p. 10, Item #6.

[14] D.13-10-041 at pp. 21-22.

[15] SOC 4 was initially adopted in D.02-10-062, and was subsequently modified in D.02-12-074 at p. 54 and D.03-06-076 at p. 27.

> Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, to include dispatching dispatchable contracts when it is most economical to do so. In administering contracts, the utilities have the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Least-cost dispatch refers to a situation where the most cost-effective mix of total resources is used, thereby minimizing the cost of delivering electric services. The utility bears the burden of proving compliance with the standard set forth in its plan. (emphasis added)

SOC 4 is incorporated into each of the utilities' Commission-approved procurement plans.[16]

A careful reading of SOC 4 highlights three key aspects for demonstrating LCD. First, a utility must "dispatch dispatchable contracts when it is economical to do so." At the time SOC 4 was written, the utilities generally controlled the dispatch of resources by submitting resource and load schedules to the CAISO. However, since the CAISO enacted its Market Redesign and Technology Upgrade ("MRTU"), the CAISO is responsible for the economic dispatch of resources in California.[17] As the Commission noted in 2011, MRTU "substantially changed the least-cost dispatch processes for SCE and other utilities."[18] Post-MRTU, the dispatch of "dispatchable resources" is accomplished by bidding these resources into the CAISO market at incremental cost. SOC 4 also anticipates that certain resources will not be dispatchable, such as QF resources with regulatory-must take agreements, hydroelectric resources that have limited operation as a result of Federal Energy Regulatory Commission ("FERC") license conditions, or nuclear facilities which are required to operate at base-load.

Second, SOC 4 requires a utility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs. Post-MRTU, this also occurs in the CAISO market. PG&E schedules all of its resources that are available into CAISO

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[16] D.11-10-002 at p. 5.

[17] Ex. PG&E-3 at p. 6-7, line 12 to p. 6-8, line 8 (quoting ORA testimony regarding the role of the CAISO with regard to LCD).

[18] D.11-10-002, FOF 1 (emphasis added).

market, as well as its load. The sale and purchase of power occur in the CAISO markets based on the CAISO's LCD algorithms.

Finally, SOC 4 requires that the use the most cost-effective mix of total resources to minimize the cost of delivering electricity to customers. This now occurs in the CAISO markets as well, where resources are bid in and the lowest-cost market solution, subject to operational constraints, minimizes costs for all customers.

In addition to SOC 4, PG&E's procurement plans in effect during the record period included a description of how PG&E dispatches its resources.[19] This description is more detailed than SOC 4 and is specific to PG&E's resources and dispatch approach.[20] SOC 4 and PG&E's bundled procurement plan are the basis for the Commission's review of PG&E's LCD activities.[21]

2. The Commission Has Not Yet Established Criteria For Demonstrating LCD Compliance

Although the language in SOC 4 and PG&E's procurement plan is relatively straightforward, the challenge is always in the details. Since SOC 4 was adopted, there have been a series of Commission decisions discussing LCD principles and the evaluation criteria for LCD. Most of these decisions have arisen in the context of an ERRA compliance proceeding for one of the three IOUs. A review of these decisions is helpful with regard to the criteria for reviewing LCD that were in effect when PG&E filed this Application.

[19] PG&E-3 at p. 6-8, lines 14-25 and Appendix G. During the record period, PG&E's 2006 Long-Term Procurement Plan ("LTPP") was in effect from January 1, 2012 to January 11, 2012. PG&E's Bundled Procurement Plan ("BPP") became effective on January 12, 2012 and was in effect during the remainder of the 2012 record period.

[20] *See* Ex. PG&E-3, Appendix G (excerpts from 2006 LTPP and BPP regarding dispatch).

[21] D.11-07-039, COL 3 (considering 2006 LTPP and SOC 4 when reviewing PG&E's LCD performance in 2009 ERRA proceeding). *See also* D.03-06-076 at p. 25 (explaining basis for LCD review as not being an after-the-fact reasonableness review); D.05-01-054 at p. 13 ("Least-cost dispatch is an up-front standard in the utilities' procurement plans. Therefore, subsequent review of dispatch should ensure that the utilities have complied with the approved procurement plans.").

The first ERRA compliance decision to address LCD and SOC 4 was D.05-01-054, which reviewed SCE's ERRA application for the September 2001 to June 2003 time period. In that decision, the Commission confirmed that the review of LCD in ERRA proceedings is a compliance review. With regards to the scope of the review, the Commission explained:

> Therefore, in the compliance review there are no ranges of possible outcomes. The outcome or standard for review has been predetermined – that is lowest cost. SCE must demonstrate that it has complied with this standard, by providing sufficient information and/or analysis in order for the Commission to verify that SCE's dispatch resulted in the most cost-effective mix of total resources, thereby minimizing the cost of delivering electric services.[22]

It is notable that the Commission did not require a precise numeric demonstration of LCD. Instead, the Commission simply required that SCE provide "sufficient information and/or analysis" to verify that SCE's dispatch resulted in the most cost-effective mix of total resources.

The Commission went on to explain in D.05-01-054 that:

> In this decision we have defined the scope of least-cost dispatch review and have indicated the utilities' responsibility for proving compliance with the least-cost dispatch standard. <u>However, at this time, the Commission has not specified criteria that should be used to determine what constitutes least-cost dispatch compliance or what the utility needs to provide to meet its burden to prove such compliance</u>. If there is a need for such criteria, it should be developed in a generic proceeding where all affected utilities, as well as interested parties, can participate.[23]

PG&E's first ERRA compliance decision was issued three months after the SCE decision. With regard to LCD, the Commission adopted in PG&E's proceeding the same scope of review used in SCE's decision three months earlier.[24]

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[22] D.05-01-054 at p. 14.

[23] D.05-01-054 at p. 15 (emphasis added).

[24] D.05-04-036 at p. 22 and FOF 7.

Although the Commission discussed in D.05-01-054 conducting a generic proceeding to develop the criteria to determine what constitutes least-cost dispatch compliance and what a utility needs to provide to meet its burden to demonstrate compliance, the generic proceeding never occurred. In 2006, the Commission noted that the criteria for least-cost dispatch had not yet been determined in a generic proceeding, nor had the generic proceeding been commenced.[25] A year later, in December 2007, the Commission again noted that there was no benchmarking method to assess LCD.[26]

Finally, in a recent decision in PG&E's 2010 ERRA Compliance proceeding, the Commission recognized that "[t]he generic proceeding suggested [in D.05-01-054] never took place . . .."[27] The lack of a generic proceeding, along with language in early ERRA Compliance decisions describing different aspects of an LCD demonstration, has, as the Commission acknowledged, created the "potential for confusion."[28] Indeed, as the Commission explained, "[a]lthough the question of what showing was required to demonstrate success in achieving LCD was raised in early ERRA compliance decisions, it was never resolved."[29] Indeed, during the hearings in this proceeding, ALJ Roscow stated that there is "a lot of ambiguity" in the Commission's LCD decisions and that many of these decisions are "kind of nuanced."[30]

In order to address this shortcoming, the Commission has now directed that the Energy Division facilitate a workshop for PG&E and other interested parties to "develop proposed criteria that should be used to determine what constitutes least-cost dispatch compliance, and the resulting methodology PG&E should follow to assemble a showing to meet its burden to provide

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[25] D.06-01-007 at pp. 5-6.

[26] D.07-12-027 at pp. 13-14.

[27] D.13-10-041 at p. 22.

[28] D.13-10-041 at p. 21.

[29] D.13-10-041 at p. 20.

[30] Transcript ("Tr.") at p. 227, line 24 to p. 228, line 3 (ALJ Roscow)

such compliance."[31] Once the workshop process is complete, the Commission will review and approve the proposals coming out of the workshop, which will then be used by the utilities in their respective ERRA Compliance applications on a prospective basis to demonstrate least-cost dispatch. In the interim, however, there is Commission guidance as to how the utilities can demonstrate least-cost dispatch. This guidance, described in more detail in the next section, was the basis for PG&E's showing in this proceeding.

3. Given That There Is No Clear LCD Compliance Criteria And The CAISO's Implementation of MRTU, The Commission Has Approved LCD Showings That Are Based On Process

In the absence of clearly-articulated criteria for demonstrating least-cost dispatch, the Commission has approved LCD compliance showings that are based on process. For example, in D.05-04-036, the first Commission decision in a PG&E ERRA Compliance proceeding, PG&E submitted testimony describing its "least cost dispatch process."[32] PG&E's testimony described how incremental costs were developed and the operational, physical, legal, regulatory, environmental, and safety constraints impacting LCD.[33] ORA protested PG&E's showing, asserting that PG&E had described its process, but had failed to make a showing that it "minimized costs to ratepayers during the record period . . ..."[34] The Commission reviewed PG&E's showing, and ORA's concerns, and concluded that PG&E has dispatched resources in a "least cost manner."[35] The Commission made this determination based on PG&E's testimony describing its LCD process.

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[31] D.13-10-041 at pp. 25-26.

[32] D.05-04-036 at p. 40.

[33] D.05-04-036 at p. 42.

[34] D.05-04-036 at p. 43.

[35] D.05-04-036 at p. 44 and FOF 16.

A year later, the Commission made a similar determination in SCE's 2004 ERRA Compliance proceeding. In that case, SCE's application included a showing regarding its LCD process.[36] The Commission determined that:

> Given the reasonableness of SCE's least-cost dispatch process and absence of a standard to assess the "most cost-effectiveness" of its hour-ahead market transactions, we must reject the disallowance recommended by DRA.[37]

The Commission did not, however, simply reject ORA's disallowance recommendation. Instead, based on the evidence before it concerning SCE's LCD processes, the Commission concluded as a matter of law that "[l]east-cost dispatch activities during the Record Period were prudently performed and complied with SOC 4 in SCE's approved procurement plan."[38] In the Ordering Paragraphs, the Commission determined that SCE's LCD activities were "reasonable and prudent."[39]

In 2009, the CAISO implemented MRTU, which created a CAISO-run least-cost dispatch process for scheduling resources bid into the CAISO's markets. The Commission recognized that MRTU "substantially changed the least-cost dispatch processes of SCE and other utilities."[40] The Commission's decision on SCE's 2009 ERRA Compliance application is the only decision to substantively address the sufficiency of an LCD showing post-MRTU.[41] To demonstrate LCD

[36] D.06-01-007 at p. 6.

[37] D.06-01-007 at p. 6 (emphasis added).

[38] D.06-01-007, COL 2.

[39] D.06-01-007, OP 1.

[40] D.11-10-002, FOF 1; *see also* D.11-07-039 at pp. 12-13 (describing structure of post-MRTU markets).

[41] The decisions on SDG&E's and PG&E's 2009 ERRA Compliance applications do not substantively address LCD. *See* D.11-07-039 at p. 11 (PG&E's 2009 ERRA Compliance application); D.11-10-029 at p. 11 (SDG&E's 2009 ERRA Compliance application). The more recent decisions issued in PG&E's and SCE's 2010 ERRA Compliance applications provide a lengthy background regarding Commission decisions on LCD, but ultimately do not substantively address how LCD is demonstrated post-MRTU. Rather, these decisions conclude that pre-MRTU Commission decisions have created a potential for confusion. *See e.g.*, D.13-10-041 at p. 21.

post-MRTU, SCE described its "scheduling and bidding processes and [its] action [that] enabled the CAISO to dispatch SCE's dispatchable resources in an economic manner during the Record Period."[42] SCE went on to assert that it had "consistently followed prudent procurement processes and practices in order to satisfy SOC 4."[43] In other words, SCE's LCD demonstration was based on testimony and evidence outlining its scheduling and bidding processes. The Commission concluded that "[b]ased on the testimony of SCE and out review of the record, we conclude that all dispatch-related activities SCE performed during the Record Period complied with Commission orders and SCE's procurement plan."[44]

The Commission's recent statements in its decision regarding PG&E's 2010 ERRA Compliance application create some confusion on this issue. The text of the decision states:

> PG&E's statement that "the Commission has repeatedly concluded that this type of information [regarding LCD strategies and processes] is sufficient to demonstrate compliance with the Commission's LCD requirements and satisfy PG&E's burden of proof" is incorrect. The Commission has never made an affirmative finding that an LCD demonstration based on strategies and processes is sufficient to demonstrate compliance with the Commission's LCD requirements and satisfy PG&E's burden of proof. Rather, the Commission, in previous ERRA compliance decisions, has either accepted and agreed with ORA's position in those instances where no disallowance was recommended, or rejected the metric-based analyses submitted by ORA in support of a disallowance.[45]

As is evident from the discussion above regarding earlier ERRA compliance decisions, the Commission has in fact concluded in previous proceedings that a discussion of processes and strategies in a utility's testimony was sufficient to allow the Commission to "conclude" that the utility's dispatch during the record period complied with LCD requirements. In these earlier

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[42] D.11-10-002 at p. 7 (emphasis added).

[43] *Id*.

[44] *Id*. (emphasis added).

[45] D.13-10-041 at p. 20.

decisions, the Commission did not simply agree with ORA, but rather affirmatively concluded that the LCD standards and requirements had been satisfied.

Obviously, one of the issues that will need to be addressed during the LCD workshops directed by D.13-10-041 will be the extent to which testimony and evidence concerning processes and strategies are a part of the demonstration of LCD. Prior Commission decisions have recognized this, although the language in the text of D.13-10-041 creates some confusion. Regardless of the outcome, however, the process and strategies used by each utility to implement LCD are clearly an important part of the LCD demonstration, especially with the implementation of MRTU.

4. The Commission Has Supported Use of The Discovery For Review of LCD Compliance

In D.05-01-054, the first ERRA compliance decision to address LCD, the Commission encouraged the use of discovery to evaluate a utility's compliance with SOC 4. In particular, the Commission noted, as explained in detail above, that there was no LCD criteria at the time and thus explained:

> In the meantime, SCE and ORA should use the master data request process, as discussed later in this decision, as a means to reach some understanding on the types of information or analyses that would be useful in demonstrating SOC 4 compliance as it related to least cost dispatch.[46]

The Commission reached a similar conclusion in D.05-04-036, PG&E's first ERRA Compliance decision, explaining that the MDRs should be developed jointly between PG&E and ORA to provide the information that ORA needs in the ERRA Compliance process.[47] Subsequent Commission decisions have also noted ORA's use of the MDR process to obtain information that ORA needed for its review of LCD.[48]

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[46] D.05-01-054 at pp. 15-16.

[47] D.05-04-036 at pp. 46-47.

[48] D.11-07-039 at p. 11.

B. PG&E Has Satisfied Its Burden of Proof And Demonstrated Least Cost Dispatch

When it prepared this Application and its Prepared Testimony, PG&E relied on the Commission's earlier decisions, described above, as the basis for its LCD demonstration in this proceeding.[49] As described in more detail below, PG&E's Prepared Testimony, Workpapers, and MDR responses clearly satisfy PG&E's burden of proof with regard to demonstrating LCD during the record period. Indeed, at the hearing, ORA's LCD witness testified that for at least the three sample days selected by ORA, PG&E had, in fact, demonstrated LCD.[50] This candid admission demonstrates that the materials provided by PG&E are sufficient to demonstrate that LCD had been achieved. PG&E also describes below its efforts to assist ORA with its review of the LCD materials and ORA's written and oral testimony supporting the conclusion that PG&E has demonstrated LCD. Finally, during the October 7-8, 2013 hearings, ORA's attorney raised some concerns in cross-examination regarding PG&E's presentation of a detailed LCD showing for three sample days. These concerns are addressed below as well.

1. PG&E Demonstrated That It Had Achieved Least Cost Dispatch Through Its Testimony, Workpapers, and MDR Responses

PG&E's LCD demonstration consists of three key elements: (1) testimony; (2) workpapers; and (3) MDR responses. All three elements have been admitted into the record in this proceeding. In addition to these three elements of PG&E's LCD demonstration, PG&E also went to substantial lengths to work with and assist ORA in its review of PG&E's LCD showing, including detailed responses to discovery requests in addition to the MDR and eight separate in-person or telephonic meetings with ORA to review LCD materials and information. At the hearings, PG&E's LCD witness, Alva Svoboda, spent considerable time on and off the record

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[49] At the time that PG&E filed this Application, the decision in PG&E's 2010 ERRA Compliance proceeding (*i.e.*, 13-10-041) had not been issued. Indeed, that decision was not issued until after the Phase 1 hearings in this proceeding.

[50] Tr. at p. 497, lines 4-8 (ORA, Mangat).

walking ALJ Roscow through the LCD materials provided by PG&E and explaining how these materials can be used to demonstrate that PG&E achieved LCD for each day during the record period. Below, PG&E describes its testimony, workpapers and MDR responses, as well as the testimony at the hearing, and explains why these materials readily satisfy the Commission requirements for demonstrating LCD. After reviewing all of this material, Mr. Svoboda concluded:

> Q: In your opinion, is all of the evidence, which was provided when PG&E filed this application, sufficient to demonstrate LCD during the record period?
>
> A: Yes.[51]

There is <u>nothing</u> in the record, other than a single conclusory sentence in ORA's testimony, to dispute this conclusion, which is based on the substantial evidence described below.

a) PG&E's Testimony Describes Its LCD Strategies and Processes For Achieving LCD

PG&E's Prepared Testimony included a detailed overview of the CAISO markets, the general and resource-specific principles and guidelines that PG&E uses to achieve LCD, an LCD process overview, and PG&E's LCD documentation and validation.[52] This is exactly the kind of LCD process cited by the Commission in earlier LCD decisions that in part formed the basis for the Commission concluding that a utility had prudently performed dispatch, complied with SOC4 and Commission orders, and complied with the utility's procurement plan with regard to LCD. However, PG&E's LCD demonstration does not rely solely on a description of PG&E's LCD process. Rather, PG&E's LCD demonstration is also based on its workpapers which contain the information necessary to demonstrate that for <u>each</u> day during the record period, PG&E achieved LCD.

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[51] Ex. PG&E-3 at p. 6-5, lines 1-3.

[52] Ex. PG&E-1, Chapter 2.

The fundamental premise underlying PG&E's LCD demonstration is that PG&E submits its bids into the CAISO markets based on incremental cost bidding, subject to regulatory, legal, operational, contractual and financial constraints.[53] Other market participants also submit bids and schedules. The CAISO takes the bids and schedules for all market participants, factors in transmission and other operational constraints, and dispatches all of the bid and scheduled resources in a least cost manner.[54] As both the Commission and ALJ Roscow have recognized, since the CAISO implemented MRTU, LCD has changed substantially.[55] Even ORA recognized that it is the CAISO that commits and dispatches resources based on the bids provided by all market participants, and that the CAISO's objective is to "minimize energy and ancillary services (A/S) procurement costs based on energy and A/S bids and transmission constraints."[56]

PG&E's testimony focuses on process and describes how PG&E develops daily forecasts of prices and load, develops its bids and schedules, submits these bids and schedules, and then validates CAISO market results. PG&E's testimony also explains the different incremental cost bidding for various types of resources, such as thermal and hydro units, and why some resources are self-scheduled.[57] All of these processes are essential elements of LCD. PG&E's workpapers then contain the actual information for each day during the record period, including price and load forecasts, bids and schedules, CAISO market results, and PG&E's after-the-fact validation. These two parts, the process description and then the actual inputs and outputs, form the basis for PG&E's LCD demonstration and are consistent with Commission precedent.

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[53] Ex. PG&E-1 at p. 2-3, lines 9-13 and p. 2-7, lines 1-17; Tr. at p. 147, line 15 to p. 149, line 4 (PG&E, Svoboda).

[54] Tr. at p. 176, lines 22-27 (PG&E, Svoboda).

[55] D.11-10-002, FOF 1; *see also* D.11-07-039 at pp. 12-13 (describing structure of post-MRTU markets); Tr. at p. 225, lines 12-14 (ALJ Roscow) ("The world has changed since the ISO took over the leadership of this [*i.e.*, MRTU] . . ..")

[56] Ex. DRA-1 at p. 5-5, lines 6-8.

[57] Ex. PG&E-1 at pp. 2-7 to 2-18.

It is notable that nowhere in ORA's testimony does ORA state that PG&E did not achieve LCD during the record period. Instead, ORA's one concern about PG&E's LCD demonstration is that PG&E did not "include a performance evaluation or other type of quantitative analysis that demonstrated PG&E's effectiveness in achieving the least-cost dispatch standard in the record year."[58] This assertion is both vague and wrong.

As a preliminary matter, ORA's testimony was vague as to what constitutes a "performance evaluation." To address this vagueness, PG&E asked in discovery for a more detailed explanation of what ORA meant by a "performance evaluation or other type of quantitative analysis." ORA provided more detail in its discovery response.[59] However, ORA's discovery response made it evident that, in fact, PG&E had already provided the exact type of analysis that ORA was requesting. As PG&E explained in its Rebuttal Testimony, the "Bid Validation" files that were included with PG&E's workpapers are exactly the type of "performance evaluation" that ORA identified in its testimony and described in discovery responses.[60] Finally, in addition to ORA's testimony being vague and wrong, it also lacked any basis for support in Commission precedent. PG&E asked ORA in discovery if it was aware of any Commission precedent or decision which requires the kind of "performance evaluation or other type of quantitative analysis" suggested by ORA. ORA candidly admitted that there is no such precedent or requirement.[61]

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[58] Ex. DRA-1 at p. 5-1, lines 20-23.

[59] Ex. PG&E-3 at p. 6-9, lines 2-15 and Appendix B (ORA Data Request response) (clarifying ORA's testimony.)

[60] Ex. PG&E-3 at p. 6-9, lines 16-23 and p. 6-10, lines 3-15. ORA's discovery response indicated that an analysis would include comparing the results of self-scheduling versus market bidding as one aspect of an LCD demonstration. However, this aspect of the analysis requested by ORA is simply not possible to do and thus ORA's request for this type of analysis is unfounded. *See* Ex. PG&E-3 at p. 6-9, line 24 to p. 6-10, line 2.

[61] Ex. PG&E-3 at p. 6-11, line 32 to p. 6-12, line 2 and Appendix B (ORA discovery response).

b) PG&E's Workpapers Contain All Of The Data and Information Necessary To Demonstrate LCD, Including Evaluations Demonstrating LCD

In its workpapers, which were admitted into the record as Exhibit PG&E-4-C, PG&E provided information regarding its LCD activities for each day during the record period. PG&E's workpapers include all of the bids and schedules submitted to the CAISO for each day during the record period, PG&E's forecasts, the market results and actual dispatch, as well as PG&E's after-the-fact evaluation of what happened in the CAISO markets.[62] PG&E's Rebuttal Testimony includes a detailed table which describes each of the items in the workpapers, what aspect of LCD that item demonstrates, and how all of this information demonstrates LCD was achieved during the entire record period.[63] PG&E's workpapers also include a narrative description that walks through three "sample days" chosen by ORA and demonstrates how the workpaper materials can be used to determine whether PG&E achieved LCD. The issue of the number of sample days is addressed in more detail below in Section III.B.4. However, of more importance than the number of sample days is the fact that both the PG&E and ORA witnesses testified at the hearing that the materials provided in the workpapers and the narrative demonstrated that PG&E had achieved LCD on the sample days.[64] In other words, ORA was able to use the information provided in PG&E's workpapers to verify that PG&E achieved LCD.

At the October 7th hearing, PG&E witness Alva Svoboda walked through PG&E's workpapers with ALJ Roscow, using Exhibit PG&E-9-C as an overview of every file included in PG&E's workpapers and how these files contained the necessary information to demonstrate that

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[62] *See e.g.* Tr. at p. 72, line 14 to p. 73, line 10 (PG&E, Svoboda) (describing after-the-fact evaluation). PG&E's workpapers do not include a hypothetical assessment of other potential market outcomes because such an assessment is simply not possible given that PG&E does not have all of the CAISO's market information. *See* Tr. at p. 65, line 16 to p. 67, line 1 (PG&E, Svoboda).

[63] Ex. PG&E-3 at p. 6-3, line 17 to p. 6-5, line 3.

[64] Tr. at p. 116, lines 21-28 (PG&E, Svoboda); p. 496, line 13 to p. 497, line 8 (ORA, Mangat); *see also* Ex. PG&E-3 at p. 6-10, line 16 to p. 6-11, line 14 (describing how sample days demonstrated LCD was achieved).

for each day during the record period, PG&E had achieved LCD. During this part of the hearing, Mr. Svoboda testified that the testimony and workpapers provided all of the information and resources necessary for the Commission and ORA to confirm what PG&E had demonstrated, that it had achieved LCD during the record period.[65]

During the hearing, ORA's attorney expressed some concern about the amount of material in PG&E's workpapers demonstrating LCD.[66] However, this concern is overstated, and the volume of materials in PG&E's workpapers is to be expected. ORA's witness indicated that he was able to review PG&E's workpapers and materials to verify that PG&E had achieved LCD for the three sample days.[67] Moreover, ORA's witness was able to go through PG&E's workpapers and identify some errors in PG&E's bids.[68] Clearly ORA was able to understand and work with the materials provided by PG&E. More fundamentally, however, it is to be expected that the materials and workpapers supporting an LCD demonstration are voluminous and data-intensive given the complexity of the CAISO markets. Each day, PG&E bids numerous UOG and contracted resources into the CAISO market. These bids are based on daily forecasts of load and price, and are submitted several times to the CAISO in both the Day-Ahead and Real Time markets. The CAISO awards bids and schedules for each resource, and PG&E then performs an after-the-fact validation of the market results. All of this data was compiled for each of the 365 days during the record period. If PG&E had not provided all of these materials, ORA may have argued that PG&E failed to satisfy its burden of proof to demonstrate LCD for each day during the record period. PG&E provided all of the information in workpapers demonstrating LCD so that it would fully satisfy its burden of proof, which it has done.

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[65] Tr. at p. 48, lines 3-9; p. 60, lines 5-25 (PG&E, Svoboda).

[66] Tr. at p. 484, line 28 to p. 485, line 3 (ORA, Haga).

[67] Tr. at p. 496, line 13 to p. 497, line 8 (ORA, Mangat).

[68] Ex. DRA-1 at pp. 5-11 to 5-12.

c) PG&E's MDRs Responses Include Additional Information Requested By ORA

Finally, in addition to the detailed description in PG&E's testimony and all of the inputs and data in workpapers, PG&E also provided detailed MDR responses to ORA concerning LCD. These responses were marked as Exhibit PG&E-10 and include further information responding to ORA requests regarding LCD.

d) PG&E's Witness Provided Detailed Testimony At The Hearing Regarding The LCD Demonstration

PG&E witness Alva Svoboda spent several hours testifying at the October 7th hearing regarding PG&E's demonstration of LCD. During his testimony, Mr. Svoboda responded to questions posed by both ORA and ALJ Roscow. Mr. Svoboda walked through all of the workpapers provided by PG&E, using Exhibit PG&E-9-C to explain all of the information included in the workpapers, the file structure of these materials, and how these materials demonstrate LCD.

Towards the end of Mr. Svoboda's testimony, ALJ Roscow asked how PG&E's workpapers could be used to determine if LCD had been achieved on a day other than the three sample days selected by ORA.[69] ALJ Roscow indicated that he would be interested in reviewing other days during the record period himself. At the October 7th hearing, Mr. Svoboda provided ALJ Roscow with a brief overview of how this would be accomplished.[70] Then, on January 16, 2014, ALJ Roscow ordered Mr. Svoboda to appear at the January 21, 2014 hearing for further examination on this issue. In preparation for the January 21st hearing, Mr. Svoboda prepared Exhibit PG&E-19-C which "identifies the key inputs and outputs to each process and how the work papers submitted can be used to demonstrate LCD for any given sample/test date during the 2012 record period."[71] Mr. Svoboda then spent an hour and a half in an off-the-record

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[69] Tr. at p. 173, lines 12-19 (PG&E, Svoboda).

[70] Tr. at p. 173, line 12 to p. 175, line 19 (PG&E, Svoboda).

[71] Ex. PG&E-19-C at p. 2.

conversation with ALJ Roscow and ORA in attendance walking through Exhibit PG&E-19-C and the workpapers to demonstrate that LCD was achieved for a random day chosen by ALJ Roscow. At the end of this lengthy off-the-record discussion, ALJ Roscow stated on the record:

> [W]hile we were off the record just now, we spent an hour, hour and a half going through [an LCD demonstration] for one day in the record period. And I'm satisfied that that's enough for me to make an attempt on my own to see how I do. And I may do that and distribute it at some point in the near future. <u>But for all intents and purposes, PG&E's fulfilled its obligation in terms of responding to my request</u>.[72]

ALJ Roscow concluded:

> And I also want to express my thanks to Mr. Svoboda and his team because, as I indicated off the record, one of the challenges is for the Commission to say that it's looked at every day and believes that least cost dispatch was accomplished or concludes that. And this will help. So I appreciate that. For this record period, for the 2012 record period. So thank you.[73]

Thus, not only did PG&E provide detailed testimony, workpapers, and MDR responses, but it also provided detailed testimony at the hearing demonstrating how the materials provided could be used to demonstrate LCD for each day during the record period. This oral testimony, in addition to all the materials that PG&E provided when it filed its Application, satisfies PG&E's burden of proof.

2. PG&E Expended Considerable Resources Assisting ORA With Its Review Of PG&E's LCD Demonstration

PG&E went to extensive effort to work with ORA's witnesses to ensure that they understood and were familiar with all of the material provided by PG&E. PG&E had eight separate meetings with ORA to review all of the LCD testimony and workpapers provided, to show how these materials can be used to demonstrate that LCD was achieved, and to answer

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[72] Tr. at p. 484, lines 3-12 (ALJ Roscow) (emphasis added).

[73] Tr. at p. 485, lines 4-13 (ALJ Roscow).

follow-up questions from ORA's witnesses.[74] Mr. Svoboda testified that PG&E did a "file-by-file" review with ORA for all of the information in PG&E's workpapers to ensure that ORA was fully aware of all of the materials in PG&E's demonstration.[75]

PG&E also answered numerous other ORA data requests regarding LCD in addition to the MDRs.[76] ORA had more than six (6) months to review these materials before preparing and serving its report in late August. In short, PG&E made substantial efforts to ensure that ORA had all of the materials it needed to review PG&E's LCD demonstration and that ORA was sufficiently able to use these materials to determine for itself if LCD had been achieved.

3. ORA's Testimony Further Demonstrates That PG&E Complied With The Commission's LCD Requirements During The Record Period

ORA's LCD testimony is somewhat confusing. ORA states at the beginning of its LCD testimony that it "cannot conclude that PG&E has met the LCD standard" because PG&E did not include a "performance evaluation or other type of quantitative analysis that demonstrated PG&E's effectiveness in achieving the least-cost dispatch standard in the record year."[77] As explained above in Section III.B.1(a), PG&E did in fact provide the exact type of performance evaluation or analysis requested by ORA. Moreover, ORA's conclusory statement in testimony is inconsistent with the remainder of ORA's testimony. For example, ORA testified that PG&E submitted bids in a manner consistent with incremental cost and that the CAISO markets now perform LCD based on market participants' bids.[78] As Mr. Svoboda explained in his testimony, these facts, which were acknowledged in ORA's testimony, are the fundamental basis for demonstrating LCD.[79]

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[74] Ex. PG&E-3 at p. 6-5, line 6 to p. 6-6, line 1.

[75] Tr. at p. 62, line 25 to p. 64, line 9 (PG&E, Svoboda).

[76] Ex. PG&E-3 at p. 6-6, line 1 to p. 6-7, line 3.

[77] Ex. DRA-1 at p. 5-1, lines 20-23.

[78] Ex. PG&E-3 at p. 6-7, line 5 to p. 6-8, line 11 (quoting ORA testimony).

[79] *Id*.

What is perhaps more telling was the testimony of ORA's LCD witness at the hearing. During cross-examination, ORA witness Ravi Mangat testified:

> Q Mr. Mangat, Judge Roscow asked you about the three sample days and whether those demonstrated that PG&E had achieved least-cost dispatch. And he asked you if you believe that PG&E had made that demonstration for those three sample days. And if I got your answer right, you said it's difficult to determine. But I didn't really hear a yes or a no, so I was wondering if you could tell us as you sit here today for the three sample days that PG&E did give you, did you believe that PG&E had adequately achieved least-cost dispatch?
>
> A Specifically for those three days? I think yes. I think that they probably -- the level of detail provided specific to those days I think was -- was helpful in understanding, you know, whether that least-cost outcome had been achieved.
>
> Q And would you then as you sit here based on that say that for those three days at least that PG&E had demonstrated that it had achieved least-cost dispatch?
>
> A I think that's fair, yeah.[80]

In other words, at least for the three sample days, ORA was able to conclude that PG&E had achieved LCD. Had ORA continued its analysis, it would have determined that PG&E achieved LCD for all of the other days during the record period as well.

4. PG&E's Use Of Three Sample Days, Which Were Identified In ORA's Master Data Request, Was Consistent With Commission Decisions

During the Phase 1 hearings, ORA's attorney questioned PG&E witness Svoboda about the use of three sample days in PG&E's response to ORA's MDRs.[81] ORA's attorney implied that three days were a very small percentage of the entire year and that this was not sufficient to demonstrate LCD compliance. This is truly remarkable assertion. As a preliminary matter, PG&E's LCD demonstration is not based solely on information concerning three sample days. Instead, PG&E provided in its workpapers a narrative discussion of three sample days chosen by

[80] Tr. at p. 496, line 13 to p. 497, line 8 (ORA, Mangat).

[81] Tr. at p. 52, lines 12-25 (PG&E, Svoboda).

ORA to walk through how the information that was being provided to ORA as a part of PG&E's testimony and workpapers demonstrated LCD. The sample days are meant to assist ORA in understanding how to use the detailed data and information provided by PG&E. However, PG&E's LCD demonstration is not limited to the three sample days. As described above, PG&E provided the necessary information and data for <u>every</u> day during the 2012 Record Period to demonstrate LCD for <u>every</u> day, not just the three sample days.

The narrative concerning the three sample days is provided in response to a data request developed by ORA.[82] As the Commission noted in D.05-01-054, if ORA wants information or analyses regarding LCD, ORA can use the master data request process to obtain that information.[83] As PG&E explained above in Section III.A.4, the Commission has directed ORA and the utilities to use the discovery process in ERRA Compliance proceedings. ORA has developed a number of data requests related to LCD, including its request for a more detailed narrative concerning three sample days during the Record Period. It is ORA that decided to request a narrative regarding three sample days, not PG&E.[84] Indeed, as PG&E witness Svoboda explained, had ORA requested a narrative regarding additional days, PG&E would have "certainly" done so.[85] The narrative provided by PG&E for the three sample days is lengthy and thus ORA appears to have decided that three sample days was sufficient.[86] For ORA to imply at hearings that the use of three sample days was insufficient is inconsistent with Commission decisions, which direct ORA to seek the analyses it believes is necessary through the master data request process, and is, at best, disingenuous given that it is ORA that has decided to limit its own request to three sample days.

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[82] Ex. PG&E-10, MDR Question 65 (requesting information about three sample days).

[83] D.05-01-054 at p. 15.

[84] Tr. at p. 61, lines 4-9 (PG&E, Svoboda).

[85] Tr. at p. 61, lines 24-27 (PG&E, Svoboda).

[86] Tr. at p. 61, line 28 to p. 62, line 13 (PG&E, Svoboda).

In D.13-10-041, which was issued well after PG&E submitted its testimony, workpapers and discovery responses in this proceeding, the Commission questioned the use of three sample days in the MDR process regarding LCD. However, in that decision, the Commission stated that PG&E's LCD showing in 2010 was "primarily based on its responses to questions in the Master Data Request" providing information about the three sample days.[87] The Commission went on to state that "it is difficult to understand why any utility would think three days of data would suffice . . .."[88] After the 2010 ERRA Compliance proceeding, PG&E changed its LCD showing and now includes detailed LCD information about <u>every</u> day during the Record Period. This information is included in workpapers, not the responses to the MDRs. As PG&E explained above, this information demonstrates LCD for <u>every</u> day during the Record Period, not simply three sample days. Although PG&E continues to provide a narrative regarding the three sample days as a narrative example of how it demonstrates LCD, the information necessary to demonstrate LCD for <u>every</u> day was included in PG&E's workpapers.

IV. UTILITY-OWNED GENERATION – HYDROELECTRIC (PG&E-1, CHAPTER 3)

A. The Reasonable Manager Standard

The Commission has stated that "utilities are held to a standard of reasonableness based upon the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act."[89]

In Decision 90-09-088, the Commission observed that "[t]he reasonable and prudent act is not limited to the optimum act, but includes a spectrum of possible acts consistent with the

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[87] D.13-10-041 at p. 23.

[88] *Id*.

[89] D.11-10-002 at p. 11, n. 2, *quoting* D.90-09-088 (37 CPUC 2d 488, 499).

utility system need, the interest of ratepayers, and the requirements of governmental agencies of competent jurisdiction."[90] In this way, the Commission reiterated that the "reasonable manager" standard is not an "infallible manager" standard; it allows for mistakes if those mistakes were grounded in reasonable assumptions based on the information at hand when faced with the need to make a decision. ORA agrees with this formulation of the standard, stating that its position "is not that a 'reasonable manager' must always make a correct decision since the utilities are not held to a 'perfect manager' standard but [to] a 'reasonable manager' standard."[91]

B. The Commission Should Consider The Overall Performance of PG&E's Portfolio In Applying The Reasonable Manager Standard

In determining whether PG&E acted as a reasonable manager with respect to its UOG resources, the Commission should first consider the overall performance of PG&E's UOG portfolio since such performance is a good indicator of reasonable management of the system. As PG&E witness Alvin Thoma testified at the hearing, "above-benchmark performance over a sustained period we believe indicates reasonable management and that that level of performance is not simply a matter of luck. It's a matter of – comes from – the management of the system."[92] Importantly, PG&E is not suggesting that specific outages be disregarded by the Commission.[93] Rather, PG&E is simply suggesting that the overall performance of PG&E's portfolio should be part of the analysis of whether PG&E acted as a reasonable manager of its UOG resources.

Furthermore, a multi-year view of the entire portfolio is appropriate for determining the reasonableness of the management of PG&E's UOG assets. A one-year snapshot of reliability results may be incomplete. Certainly with respect to hydro resources, operating results can be

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[90] D.90-09-088, 37 CPUC 2d 488, 499 (1990).

[91] Ex. PG&E-3 at p. B-15 (ORA's Response to PG&E Data Request Set 4, Question 1(d)).

[92] Tr. at p. 256, lines 11-17 (PG&E, Thoma).

[93] Tr. at p. 256, lines 18-25 (PG&E, Thoma).

heavily influenced by single-year adverse events, such as major wildfires, severe weather, equipment failure or other issues outside PG&E's control.

The performance of PG&E's conventional hydro resources over the past five years has been exceptional as compared to industry benchmarks. One of the key industry metrics used to gauge the operating performance of generating units is the Forced Outage Factor ("FOF"). FOF is the ratio of the hours a unit is forced out of operation to the total hours in the operation period (*e.g.*, month, year). Lower numbers indicate greater availability. PG&E's hydro portfolio results have consistently out-performed industry FOF benchmarks over the past five years. PG&E's 5-year average (2007-2011) FOF for conventional hydro is 2.07 percent, better than the most currently available industry benchmark of 2.59 percent for the same time period.[94] Including the performance from 2012 in the 5-year average (2008-2012) yields a FOF of 2.51 percent, better than the 2.59 percent industry benchmark.[95] For PG&E's conventional large hydro resources (i.e., units greater than 30 megawatts), which includes 39 units and represents 83.5 percent of PG&E's conventional hydro generation capacity, the comparison is even more impressive. PG&E's 5-year average (2007-2011) FOF for this grouping of critical units is 1.66 percent compared to the industry benchmark of 2.52 percent for the same period.[96] Including 2012 performance in the 5-year average (2008-2012) yields a FOF of 2.01 percent which is still better than the industry benchmark of 2.52 percent.[97]

The level of performance of PG&E's hydro portfolio compared to industry benchmarks indicates that PG&E is operating its hydro portfolio as a reasonable manager would. ORA's

[94] Ex. PG&E-3 at p. 3-3, lines 1-4.

[95] Ex. PG&E-3 at p. 3-3, lines 4-6.

[96] Ex. PG&E-3 at p. 3-3, lines 9-11.

[97] Ex. PG&E-3 at p. 3-3, lines 11-13.

narrow focus on individual forced outages does not account for the overall performance PG&E achieved with its hydro portfolio.

It is also important to note that, notwithstanding the complexity and extent of PG&E's conventional hydro system, consisting of 67 powerhouses with 106 generating units located on 16 rivers and including 98 reservoirs, 73 diversions, 171 dams, 173 miles of canals, 43 miles of flumes, 132 miles of tunnels, and 65 miles of pipe (penstocks, siphons, and low head pipes),[98] ORA has recommended a disallowance related to a single outage, at the Belden powerhouse hydroelectric facility. Yet, even considering the Belden forced outage, PG&E's 2008-2012 performance of its hydro portfolio was better than industry benchmarks. PG&E believes the Commission should recognize PG&E's overall performance when considering ORA's disallowance recommendation.

C. Background of the Belden Outage

ORA recommends a disallowance for a forced outage at the Belden powerhouse hydroelectric facility (Belden).[99] On July 13, 2012, Belden Powerhouse tripped off-line due to a failed pipe fitting on the generating unit's Oil Spill Prevention Program pump skid (OSPP skid).[100] Specifically, a pump pressure gauge broke off at a threaded nipple of the pump casing.[101] As a result, oil in the upper guide bearing tub drained to the point where the bearing excess high temperature alarm tripped the unit.[102] The bearing tub had an oil level monitoring device that should have tripped the unit before the bearing reached an excessive temperature, but

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[98] Ex. PG&E-1 at p. 3-1, lines 7-8; 18; 24-26.

[99] Ex. DRA-1 at p. 2-1, lines 15-20.

[100] Ex. PG&E-1 at p. 3-35, lines 18-20; Ex. DRA-1-C (Ex. 2.7, p. 2, lines 27-37). The OSPP skid cools the lubricating oil pumped to, and returned from, the upper guide and thrust bearing reservoir. *See* Ex. DRA-1-C (Ex. 2.7 at p. 2, lines 39-40).

[101] Ex. DRA-1-C (Ex. 2.7 at p. 2, lines 30-32).

[102] Ex. PG&E-1 at p. 3-35, lines 20-22.

the instrumentation failed to operate as designed.[103] The failure was caused by a pinched wire that occurred when the oil level device cover was re-installed after a routine inspection of the device in March, 2012.[104]

Although all the oil was contained inside the powerhouse, the oil spill contaminated the powerhouse basement and sumps and required a significant cleanup effort.[105] The guide bearing and failed pipe fitting replacements were completed concurrently with the spill cleanup allowing the unit to return to service on September 16, 2012.[106]

The OSPP skid was installed with a liquid leak detection alarm (separate from the oil level device that failed) that was designed to notify PG&E's Caribou Switching Center in the event of a spill of either oil or water. However, the OSPP liquid leak detection alarm had been removed for repair on May 16, 2012.[107]

1. PG&E Acted As A Reasonable Manager With Regard To The Belden Facility

ORA asserts that PG&E "failed to show that it acted as a reasonable manager would have" with respect to the Belden outage by (1) failing to test the low oil level device upon taking the liquid leak detection device out of service; (2) accepting the installation of the OSPP skid pressure gauge in its as-built location; and (3) failing to have contingency plans or other protocols in place relating to inoperable OSPP skid liquid leak detection alarms.[108] All of ORA's assertions lack merit.

[103] Ex. PG&E-1 at p. 3-35, lines 23-27.

[104] Ex. DRA-1-C (Ex. 2.7 at p. 2, lines 45-47; Exhibit 2.10).

[105] Ex. PG&E-1 at p. 3-35, lines 22-23 and 30-31.

[106] Ex. PG&E-1 at p. 3-35, lines 31-34.

[107] Ex. DRA-1-C (Ex. 2.7 at p. 3, lines 110-114; Exhibit 2.10).

[108] Ex. DRA-1 at p. 2-18, lines 8-15; and at p. 2-20, lines 1-15.

2. It Was Reasonable for PG&E not to Re-Test the Low Oil Level Device upon Taking the Liquid Leak Detection Alarm Out of Service.

ORA acknowledges that PG&E's request to take the liquid leak detection alarm out of service due to the nuisance alarms "was properly requested and granted to PG&E's staff by management."[109] Nevertheless, ORA recommends a disallowance for the outage. ORA's principal assertion is that PG&E failed to show that it acted as a reasonable manager would have because it "[f]ailed to test or visually inspect the bearing low level alarm that was the only alarm remaining in place to alert PG&E to a potential oil spill."[110]

ORA's argument, that PG&E, upon taking the liquid leak detection alarm out of service for repair should have tested the low oil level device, is premised on the assumption that the liquid leak detection alarm and the low oil level device are designed to be redundant systems, with one device intended to back-stop the other in case one of them fails. That assumption is incorrect. In fact, the two devices have very different functions. The liquid leak detection alarm is an informational alarm, typically referred to in the industry as a trouble alarm, the purpose of which is to advise the operator of a potential problem that should be investigated.[111] It is simply an alarm, and one of a general nature that gives no indication of the precise problem.[112] In contrast, the purpose of the low oil level device is to protect the unit from damage by shutting it down.[113] Thus, the two devices have very different functions.[114] They are not intended to back-stop one another. Consequently, it does not follow as a matter of logic that one would test the low oil level alarm just because the liquid leak detection device had been taken out of service.

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[109] Ex. DRA-1-C at p. 2-15, lines 27-28.

[110] Ex. DRA-1-C at p. 2-18, lines 10-12.

[111] Tr. at p. 247, lines 20-24 (PG&E, Thoma).

[112] Ex. PG&E-3 at p. 3-7, lines 9-12.

[113] Tr. at p. 247, lines 17-20, and at p. 249, lines 8-13 (PG&E, Thoma).

[114] Tr. at p. 247, lines 24-25 (PG&E, Thoma).

ORA's assertion that PG&E should have tested the low oil level device when it took the liquid leak detection alarm out of service is analogous to suggesting that if a homeowner's burglar alarm is malfunctioning and taken out of service, the homeowner should test the house's other alarm systems, for example, the fire alarm. However, as ORA's witness conceded, it would make no sense for the homeowner to test the other alarms since they have separate functions and operate independently of the burglar alarm.[115] The same logic applies to ORA's assertion that PG&E should have tested the low oil level device when it took the liquid leak detection alarm out of service. Because they have separate functions and operate independently of each other, it would not be logical to test one simply because the other is taken out of service.

Moreover, even if it were logical to confirm that the low oil level device was functioning properly upon taking the liquid leak detection alarm out of service, it still would have been reasonable not to test the low oil level device because PG&E had tested it only two months prior to taking the liquid leak detection alarm out of service[116] and it passed that test.[117] In addition, PG&E has literally dozens of similar low oil level devices deployed throughout its hydro system and they have been extremely reliable, with no other pinched wire incidents.[118] Thus, there would have been no reason to suspect that the low oil level device was not functioning properly and, therefore, no reason to test the low oil level device.

Finally, most of the 67 powerhouses in PG&E's hydro system operate now, and have operated for decades, without liquid leak detectors and their associated alarms.[119] Consequently, temporary removal of the liquid leak detection alarm returned Belden to the same level of alarms

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[115] Tr. at p. 367, line 4 to p. 368, line 1 (ORA, Lasko).

[116] Ex. DRA-1-C (Ex. 2.10)(PG&E completed test of low oil level device on March 7, 2012; liquid leak detection alarm taken out of service on May 16, 2012).

[117] Ex. PG&E-3 at p. 3-4, lines 14-16.

[118] Ex. PG&E-3 at p. 3-4, lines 16-19.

[119] Ex. PG&E-3 at p. 3-5, lines 7-8.

and controls that were in place before installation of the OSPP skid, and to the current level of most of the powerhouses in PG&E's system.[120] Under such circumstances, it was reasonable not to re-test the low oil level device once the liquid leak detection alarm was taken out of service since the resulting alarm configuration was typical of that found throughout PG&E's hydro system.[121]

In summary, it was reasonable under the circumstances for PG&E not to re-test the low oil level device when it took the liquid leak detection alarm out of service. From the technician's point of view, he was dispatched to disable the liquid leak detection alarm. He had no reason to test the low oil level alarm at that time since the two devices perform different functions and operate independently of each other. Even if that were not the case, and the two devices were inextricably linked in some way or otherwise designed to serve as back-up systems for one another, it still would have been reasonable for the technician not to test the low oil level device since it had been tested only two months prior and been found to be in working order. Knowing that, why then would the technician take the time to re-test it, particularly given the device's stellar reliability record as deployed throughout PG&E's hydro system? The suggestion that on these facts the technician should have nonetheless re-tested the low oil level device is unreasonable.

3. It was Reasonable for PG&E to Accept the Vendor's Installation of the OSPP Skid, Including the Location of the Pressure Gauge.

ORA further asserts that PG&E failed to meet the "reasonable manager" standard by installing the pressure gauge that broke off the pump casing in a "high-vibration zone" which was inconsistent with the design.[122] PG&E disagrees with ORA's assertions for several reasons.

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[120] Ex. PG&E-3 at p. 3-5, lines 8-12.

[121] Ex. PG&E-3 at p. 3-5, lines 12-16.

[122] Ex. DRA-1-C at p. 2-20, lines 1-15.

First, PG&E has a number of other similar OSPP skids that were similarly designed and installed prior to the installation at Belden in 2011 that have operated satisfactorily for years and have never experienced a failure similar to the unit at Belden.[123]

Second, the third-party fabricator of the skid had determined that the location of the gauge was appropriate.[124] The vendor has extensive experience fabricating skids.[125] Indeed, the vendor has been supplying similar skid packages to industry since the 1960s.[126] Moreover, the vendor provided on-site support at most of PG&E's skid sites during their respective startup and testing phases and tested all of the skid controls in its fabrication facility prior to shipment (which testing was witnessed by PG&E's responsible engineer).[127] PG&E reasonably relied on the vendor's expert assessment that the location of the gauge was appropriate given the vendor's substantial expertise with skid design, fabrication and installation.

Third, the vendor indicated that other customers have installed OSPP heat exchanger/pump skids with the pressure gauges located between the pump and the expansion joint, identical to the as-built unit at Belden.[128]

Finally, although, as ORA notes, the conceptual design showed the pressure gauge on the opposite side of the expansion joint from where it was actually installed, the conceptual design was just that – conceptual.[129] Although ORA's witness conceded that he was not familiar with the term "conceptual design,"[130] in practice there is a significant distinction between a

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[123] Ex. PG&E-3 at p. 3-5 line 30 to p. 3-6 line 2; Ex. DRA-1-C (Ex. 2.7 at p. 5, line 184).

[124] Ex. PG&E-3 at p. 3-6, lines 2-3.

[125] Tr. at p. 240, line 24 to p. 241, line 5 (PG&E, Thoma).

[126] Ex. DRA-1-C (Ex. 2.7 at p. 26, lines 545-546).

[127] Ex. DRA-1-C (Ex. 2.7 at p. 26, lines 539-543).

[128] Ex. PG&E-3 at p. 3-6, lines 6-9.

[129] Ex. PG&E-12-C; Tr. at p. 366, lines 17-23 (ORA, Lasko).

[130] Tr. at p. 366, line 23 to p. 367, line 3 (ORA, Lasko).

"conceptual design" on the one hand, and a "detailed design" on the other. A "conceptual design" is a high-level design[131] and is typically just a rough draft drawing of the basic idea under evaluation, while a "detailed design," as the name suggests, is more detailed and further along the design process.[132] Thus, just because the "conceptual design" showed the pressure gauge on one side of the expansion joint does not suggest it was unreasonable to install it on the opposite side. A "conceptual design" is not intended to convey such detailed installation requirements.

For all these reasons, it was reasonable for PG&E to accept the OSPP skid vendor's installation, including the placement of the pressure gauge.

4. It was Reasonable for PG&E not to have Contingency Plans or other Protocols in Place Relating to Inoperable OSPP Skid Liquid Leak Detection Alarms.

ORA also asserts that PG&E was not a reasonable manager since it did not have "contingency plans, safeguards, or procedures to guide PG&E's personnel regarding the equipment that should be inspected to prevent potential incidents when the liquid leakage detection alarm becomes purposefully disabled or inoperable."[133] ORA further asserts that "[p]roper documentation would have provided PG&E's personnel with a description of the combinations of reasonable occurrences and conditions that would result in an unwanted event following the disabling of the OSPP skid liquid leakage detection alarm."[134]

These assertions are misplaced. Most of PG&E's powerhouses do not have OSPP skids, and of those that do, many do not have liquid leak detection alarms[135] since they are not a

[131] Tr. at p. 240, lines 22-24 (PG&E, Thoma).

[132] *See e.g.,* http://wiki.answers.com/Q/What_is_conceptual_design_and_detailed_design

[133] Ex. DRA-1-C at p. 2-18, lines 2-4.

[134] Ex. DRA-1-C at p. 2-18, lines 4-7.

[135] Ex. PG&E-3 at p. 3-4, lines 26-27.

required or otherwise necessary component of a hydro unit.[136] Thus, it was reasonable not to have a contingency plan or other protocol in place for when such alarms were not operable. There simply was (and there remains) no need for such protocols. Furthermore, even if such protocols were appropriate, it would be reasonable for them not to include a requirement to re-test the low oil level device since, as discussed above, such devices have a separate function and operate independently of liquid leak detection alarms.

D. ORA's Disallowance Calculation is Overstated

ORA recommends a disallowance for the Belden outage of $1,968,220.[137] As discussed above, PG&E does not believe any disallowance is appropriate since PG&E acted as a prudent and reasonable manager with respect to the Belden outage. However, if the Commission were to determine otherwise, it should disallow only $1,324,811 since ORA's replacement cost analysis for the outage is flawed. Specifically, in its replacement power cost calculation, ORA used a proxy period to estimate an average hourly net CAISO award of megawatts and assumed that Belden would have been dispatched in this amount during each hour of the July 13, 2012 to September 16, 2012 outage.[138] In doing so, ORA failed to recognize that PG&E held back water during the Belden outage so that PG&E's customers could get the benefit of that water after the outage had ended.[139] Rather than using an assumed average hourly net CAISO award for Belden during the outage, ORA should have calculated the amount of energy lost due to water spilled or bypassed around Belden during the outage as well as the cost of that lost energy.[140] ORA's witness conceded this point at hearing.[141] Correcting the methodology in this way yields a

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[136] Ex. PG&E-3 at p. 3-5, lines 1-3 (describing the alarms as "an extra safeguard").

[137] Ex. DRA-1-C at p. 2-14, line 17.

[138] Ex. PG&E-3-C at p. 3-8, lines 1-5.

[139] Ex. PG&E-3 at p. 3-8, lines 7-9.

[140] Ex. PG&E-3 at p. 3-8, lines 9-13.

[141] Tr. at p. 372, line 27 to p. 373, line 17 (ORA, Lasko).

replacement power cost for the outage of $1,324,811.[142] Although he could not verify some of the variables utilized in PG&E's calculations, such as acre-feet spilled, ORA's witness did confirm the soundness of the methodology[143] as well as the average nodal price used by PG&E in its calculations.[144]

Consequently, a disallowance of $1,324,811 would be appropriate if the Commission were to find (which it should not) that PG&E failed to act as a prudent and reasonable manager with respect to the Belden outage.

V. UTILITY-OWNED GENERATION – SOLAR PHOTOVOLTAIC AND FUEL CELLS (EXHIBIT PG&E-1, CHAPTER 4)

During the record period, PG&E owned, operated, and maintained seven ground-mounted photovoltaic ("PV") solar stations and two fuel cell facilities.[145] PG&E's PV generating facilities provided approximately 165,307 MW hours of energy during the 2012 record period.[146] PG&E's fuel cell generating facilities generated approximately 22,232 MW hours of energy during the 2012 record period.[147]

PG&E's PV generating facilities sustained three forced outages longer than 24 hours in duration during the record period.[148] PG&E's fuel cell facilities sustained two forced outages longer than 24 hours in duration during the record period.[149] In its testimony, ORA did not raise any issues or concerns regarding these outages or PG&E's management of its PV and fuel cell facilities. Based on PG&E's undisputed testimony, the Commission should find that PG&E

[142] Ex. PG&E-3-C, Appendix C (Belden Replacement Power Calculation).

[143] Tr. at p. 374, lines 1-28 (ORA, Lasko).

[144] Tr. at p. 378, lines 1-14 (ORA, Lasko).

[145] Ex. PG&E-1 at p. 4-1, lines 1-3.

[146] Ex. PG&E-1 at p. 4-12, lines 1-2.

[147] Ex. PG&E-1 at p. 4-12, lines 2-4.

[148] Ex. PG&E-1 at p. 4-12, line 9 to p. 4-14, line 25.

[149] Ex. PG&E-1 at p. 4-14, line 27 to p. 4-15, line 18.

acted as a reasonable manager with respect to its PV and fuel cell facilities during the 2012 record period.

VI. UTILITY-OWNED GENERATION – FOSSIL (EXHIBIT PG&E-1, CHAPTER 5)

As with its hydro units, in evaluating whether PG&E acted as a reasonable manager of its fossil generating assets it is important to consider how those assets performed as compared to industry benchmarks. In both 2011 and 2012, PG&E's fossil fuel generating stations performed significantly better than industry benchmarks across the board.[150] ORA does not dispute this fact.

ORA recommends a disallowance of $87,000 for a maintenance outage at PG&E's Humboldt Bay Generating Station ("HBGS") that occurred on Unit 5 beginning on December 19, 2012.[151] The outage was originally planned for two days to address a maintenance service bulletin circulated by the manufacturer of the HBGS turbocharger components, but was extended through the end of the record period due to damage that was discovered in the turbocharger while performing the service bulletin maintenance work.[152] Because this outage was completely out of PG&E's control, the Commission should reject ORA's recommended disallowance, as explained in more detail below. Moreover, the disallowance calculation itself is deeply flawed and should be rejected by the Commission even if it deems a disallowance appropriate.

As a preliminary matter, ORA ignores the fact that in 2012 HBGS performed at a reliability level that significantly exceeded the reciprocating engine industry benchmarks. Specifically, in 2012, the HBGS equivalent availability factor was 95.4 percent, or 14.1

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[150] Ex. PG&E-3 at p. 4-3, line 5 to p. 4-4, line 6.

[151] Ex. DRA-1-C at p. 3-2, line 12 to. 3-3, line 8. In its prepared testimony, ORA recommended a disallowance of $1.7 million, consisting of capital and labor costs of $1.61 million and foregone energy costs of $87,000. *See* Ex. DRA-1 at p. 3-3, lines 6-9. At hearing, however, ORA withdrew the $1.61 million recommended disallowance relating to capital and labor costs because PG&E did not include any such costs in its filing. *See* Tr. at p. 380, line 17 to p. 385, line 6 (ORA, Mangat).

[152] Ex. DRA-1-C at p. 3-2, lines 14-15; at p. 3-4, lines 10-14.

percentage points better than the industry benchmark,[153] while the HBGS equivalent forced outage rate was 1.37 percent, or 25.11 percent better than the industry benchmark.[154] In addition to the outage specific facts, which are described below, the Commission should consider this outstanding performance in evaluating whether PG&E acted as a reasonable manager of its fossil generating assets, and of HBGS in particular.

A. Description of the HBGS Unit 5 Outage

The HBGS Unit 5 outage was described by PG&E's witness at the hearing as follows:

> What happened with Unit 5 was we took the engine out of service in a scheduled maintenance outage to inspect the turbocharger as a result of a service bulletin that the . . . turbocharger manufacturer had submitted.
>
> And when we took Unit -- the Engine 5 out of service and removed the insulation off the turbocharger and disassembled the turbocharger, we noticed that the turbocharger turbine, which is the component that the exhaust gases go through – turbine spins, and it spins the compressor which helps increase the air pressure for combustion in the engine. But the turbines had some damage in the blades, and we recognized that it was from some metal fragments that seemed to have entered that turbine area.
>
> So when we noticed that, it was very -- it was a prudent thing to take – to extend that outage to get that turbocharger repaired because these turbochargers run at a very high RPM. And if you have any damages to those blades, it could be a safety issue. They could throw a blade, and it would injure somebody or damage other equipment. So it was prudent to take that engine out of service to get that turbocharger repaired and also to figure out why there was damage so we could prevent that from happening in the future because we've got 9 other engines right.[155]

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[153] Ex. PG&E-3 at p. 4-4, lines 9-11.

[154] Ex. PG&E-3 at p. 4-4, lines 11-12.

[155] Tr. at p. 285, line 26 to p. 287, line 2 (PG&E, Bosscawen).

It was ultimately determined that the damage to the turbocharger had been caused by the cracking of the inner liner in the exhaust manifold expansion joint.[156] This additional damage led to the prolongation of the outage.[157]

ORA recommends a disallowance for the outage on the grounds that PG&E allegedly failed to demonstrate that it: (1) sufficiently verified the credentials of the engine manufacturer; (2) followed the recommended maintenance schedule for the components acquired, and (3) met its obligation to minimize costs to ratepayers by ensuring that the engine manufacturer would bear the costs of foregone energy from HBGS in the event of component failure (due to manufacture or installation errors).[158] ORA also expresses concern over PG&E's decision to have the engine manufacturer investigate the cause of the turbocharger damage, stating that a conflict of interest was presented by such an arrangement.[159] None of these assertions has merit.

B. PG&E Acted as a Prudent and Reasonable Manager of HBGS

1. Consideration of the Engine Manufacturer's Credentials Is Not Properly Within the Scope of this Proceeding.

ORA asserts that PG&E failed to demonstrate that it used the judgment of a reasonable manager in selecting the company to manufacturer and install the engine components at HBGS.[160] ORA also asserts that PG&E failed to provide proof that the installing company had a track record of reliable installations equal to or higher than industry standards.[161] These assertions are baseless.

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[156] Ex. DRA-1-C at p. 3-2, lines 19-22; Tr. at p. 288, lines 7-9 (PG&E, Bosscawen).

[157] Ex. DRA-1-C at p. 3-2, lines 22-23.

[158] Ex. DRA-1-C at p. 3-2, line 26 to p. 3-3, line 5.

[159] Ex. DRA-1-C at p. 3-11, lines 17-20.

[160] Ex. DRA-1 at p. 3-11, lines 21-23.

[161] Ex. DRA-1 at p. 3-11, lines 25-27.

As an initial matter, PG&E does not believe that the issue of the engine manufacturer's credentials is properly within the scope of this proceeding. The Engineering, Procurement, and Construction ("EPC") contract that PG&E executed with the engine manufacturer, and to which ORA now objects, was approved by the Commission eight years ago, in 2006. During the course of PG&E's 2004 Long-Term Request for Offers ("LTRFO") proceeding, PG&E filed extensive testimony with the Commission describing, among other things, this specific EPC contract. As noted, the Commission approved the EPC contract in 2006.[162] ORA's attempt – now some eight years later – to have the Commission revisit its decision is inappropriate. ORA's request is even more striking given that ORA participated in the 2004 proceeding in which PG&E sought approval of the EPC, and ORA's witness specifically stated in 2004 that ORA did not oppose PG&E's selection of the engine manufacturer.[163] Thus, ORA's suggestion that PG&E was somehow unreasonable in selecting the engine manufacturer for HBGS is unavailing.

Moreover, as discussed above, the overall performance of HBGS undermines wholesale ORA's claim that PG&E acted unreasonably in selecting the engine manufacturer since HBGS has performed at a reliability level that significantly exceeds reciprocating engine industry benchmarks.

2. PG&E Did Follow the Recommended Maintenance Schedule and Could Not Have Discovered the Problem Simply by Following the Manufacturer's Recommended Maintenance Schedule

ORA asserts that PG&E failed to implement regular inspections of HBGS and to ensure that any necessary maintenance and testing activities were undertaken in a timely fashion during the record period in compliance with the engine manufacturer's maintenance schedule.[164] More

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[162] D.06-11-048.

[163] DRA's July 28, 2006 Testimony in PG&E's 2004 Long-Term RFO Proceeding (A.06-04-012), p. 4-8, lines 21-22.

[164] Ex. DRA-1-C at p. 3-10, lines 21-24.

specifically, ORA claims that PG&E should have conducted daily routine inspections of the engines, as well as water cleaning of the turbocharger compressor every 50 operating hours and water cleaning of the turbocharger turbine every 100 operating hours.[165] ORA further contends that had PG&E followed these guidelines, it would have discovered the damage to the turbocharger turbine prior to the maintenance outage scheduled in response to the unrelated service bulletin from the turbocharger manufacturer.[166] ORA's assertions are unsupported, lack credibility, and should be rejected by the Commission.

First, as PG&E points out in its rebuttal testimony, PG&E does (and did in 2012) perform all the operations and maintenance recommendations from the engine manufacturer.[167] Specifically, PG&E performs daily routine inspections of the engines as well as water cleaning of the turbocharger compressor every 50 operating hours as part of its routine operations.[168] In fact, PG&E performs the recommended daily routine inspections twice per day.[169]

Second, ORA's assertion that had PG&E followed the engine manufacturer's maintenance recommendations (which, as noted above, it did), PG&E would have discovered the damage to the turbocharger turbine prior to the maintenance outage, is simply not credible.

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[165] Ex. DRA-1-C at p. 3-10, lines 7-10.

[166] Ex. DRA-1-C at p. 3-10, lines 10-13.

[167] Ex. PG&E-3 at p. 4-6, lines 20-21.

[168] Ex. PG&E-3 at p. 4-6, lines 21-23. Note that PG&E does not routinely perform water cleaning of the turbocharger turbine every 100 operating hours because the maintenance schedule only recommends such cleaning for engines that burn exclusively heavy fuel oil, which the engines at HBGS do not. Ex. PG&E-3 at p. 4-6, lines 23-27. *See also*, Ex. PG&E-6 (recommended maintenance schedule).

[169] Ex. PG&E-3 at p. 4-7, lines 4-5. Evidence of daily routine engine inspections, as well as water cleaning of the turbocharger compressors, is included in Ex. PG&E-3, Appendix E (HBGS Engine and BOP Checklist and Sample Operator Log). While ORA claims that it requested such evidence in discovery and that PG&E failed to produce it, PG&E did not interpret the specific ORA data request as seeking this information. *See* Tr. at p. 277, line 16, to p. 280, line 22 (PG&E, Bosscawen). There was certainly no effort by PG&E to withhold this information. *See* Tr. at p. 296, lines 1-16 (PG&E, Bosscawen). Indeed, it is not clear why PG&E would choose to withhold evidence of its compliance with the engine manufacturer's recommended maintenance schedule. In any event, it is undisputed that PG&E did comply with the maintenance schedule.

Specifically, ORA claims that a significant difference in audible sounds, caused by the movement of small cracked fragments from the inner liner, should have been noticeable to PG&E during its routine external monitoring.[170] The suggestion that PG&E personnel should have been able to hear a small piece of metal fragment travel downstream from the exhaust manifold expansion joint to the turbocharger is specious. The sound level in the HBGS engine hall is extremely high, between 102 and 112 decibels according to a 2011 noise survey, and far too loud for PG&E personnel to hear a small piece of metal fragment travel downstream from the exhaust manifold expansion joint to the turbocharger.[171] In addition, employees are required to wear hearing protection whenever they enter the engine hall.[172] Hearing protection would make it even more difficult to hear a small piece of metal fragment travel downstream from the exhaust manifold expansion joint to the turbocharger.[173] Finally, even if it was possible to hear a small piece of metal fragment travel downstream from the exhaust manifold expansion joint to the turbocharger in a 102-112 decibel environment with hearing protection, it would be extremely unlikely that PG&E personnel would be conducting a routine inspection of an engine at the exact moment a metal fragment broke loose and traveled downstream from the exhaust manifold expansion joint to the turbocharger.[174]

Equally unavailing is ORA's assertion that the broken metal fragments from the inner liner should have been discovered during the routine water cleaning of the turbocharger compressor and turbine.[175] In order to access the inside of the turbocharger to see the

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[170] Ex. DRA-1-C at p. 3-11, lines 5-11.

[171] Ex. PG&E-3 at p. 4-8, lines 18-22; Appendix E (results of HBGS noise survey). Note that 102 to 112 decibels is similar to the sound of a power saw at 3 feet away or the sound of a loud rock concert. *Id.* at p. 4-8, n. 14.

[172] Ex. PG&E-3 at p. 4-8, lines 23-24.

[173] Ex. PG&E-3 at p. 4-8, lines 24-27.

[174] Ex. PG&E-3 at p. 4-8, line 27 to p. 4-9, line 3.

[175] Ex. DRA-1-C at p. 3-11, lines 1-3.

compressor or turbine, the engine needs to be shut down and cooled and the turbocharger needs to be disassembled.[176] Water cleaning of the turbocharger compressor and turbine, however, is performed while the engine is operating, through the use of external piping that directs water into the upstream side of the turbocharger compressor and turbine.[177] It would have been impossible for PG&E personnel to see the inside of the turbocharger during the routine water cleanings and, therefore, impossible for PG&E to discover the broken metal fragments from the inner liner as ORA asserts.[178]

The fact is that the first recommended maintenance activity that would have resulted in discovery of damage to the turbocharger turbine would have been the 12,000-hour turbocharger dismount and clean maintenance activity.[179] The only unit that had reached this number of operating hours at the time PG&E received the service bulletin was Unit 1.[180] PG&E did conduct this maintenance activity as scheduled on Unit 1 beginning November 8, 2012 and did not find any turbocharger damage caused by the exhaust gas manifold bellows inner liner.[181] Prior to this maintenance activity on Unit 5, there would have been no discernible indications of a problem with the turbocharger. Indeed, PG&E had not noticed any variations in the performance of Unit 5 prior to the maintenance outage.[182]

In short, ORA's claim that PG&E should have noticed the damage to the turbocharger during routine external monitoring and water cleanings is not reasonable.

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[176] Ex. PG&E-3 at p. 4-8, lines 1-3.

[177] Ex. PG&E-3 at p. 4-8, lines 3-6.

[178] Ex. PG&E-3 at p. 4-8, lines 6-9.

[179] Ex. PG&E-3 at p. 4-7, lines 17-20.

[180] Ex. PG&E-3 at p. 4-7. lines 21-22.

[181] Ex. PG&E-3 at p. 4-7, lines 22-25.

[182] Tr. at p. 285, lines 19-21 (PG&E, Bosscawen).

3. The HBGS Warranty was Commercially Reasonable

ORA claims that PG&E failed to act as a reasonable manager because it did not require the engine manufacturer to "provide a warranty that would cover net energy replacement for manufacturing and installation defects."[183] As an initial matter, PG&E does not believe that the propriety of the vendor warranty is properly within the scope of this proceeding. As discussed above, PG&E entered into an EPC contract with the engine manufacturer for HBGS resulting from PG&E's 2004 LTRFO. The warranty was part of that EPC contract. The Commission found that the EPC contract was reasonable and approved it in Decision 06-11-048. If ORA had concerns with the EPC contract, it should have raised those concerns in the 2004 LTRFO proceeding, not nearly a decade later in this proceeding.

In any event, ORA's assertion that PG&E should have obtained a warranty from the engine manufacturer that included reimbursement for replacement power costs resulting from manufacturing and installation defects is unreasonable. As PG&E's witness testified, "In my 30 years of experience, I am not aware of any major power plant equipment EPC warranties that require the original equipment manufacturer to cover net energy replacement for manufacturing and installation defects."[184]

ORA claims to be aware of one such warranty, in a contract between SCE and Mistsubishi Heavy Industries, Ltd. (Mitsubishi) relating to the replacement steam generators at the San Onofre Nuclear Generating Station.[185] However, ORA did not produce a copy of the actual contract; instead it produced a copy of a letter written by SCE's attorneys to Mitsubishi alleging that Mitsubishi was in breach of several provisions of their contract and setting forth SCE's alleged damages.[186] However, it is clear from the letter (termed a "Notice of Dispute")

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[183] Ex. DRA-1-C at p. 3-12, lines 21-23.

[184] Ex. PG&E-3 at p. 4-10, lines 29-31.

[185] Ex. PG&E-14; Tr. at p. 386, lines 10-20 (ORA, Mangat).

[186] Ex. PG&E-14. At the hearing, ORA's witness conceded that he had not reviewed the contract itself.

that the underlying contract does not contain a warranty along the lines suggested by ORA. Specifically, the letter refers to a contractual provision whereby SCE waives any claims for consequential damages.[187] The incurrence of replacement power costs as a result of a manufacturing or installation defect is a quintessential example of consequential damages.[188] Thus, ORA's reliance on the SCE-Mitsubishi contract is misplaced.

4. The Engine Manufacturer Did Not Have a Conflict of Interest and Its Root Cause Analysis Was Appropriate

ORA expresses concern that the engine manufacturer had a conflict of interest in its role as both supplier and investigator of the turbocharger damage, and suggests this conflict of interest is further evidence of PG&E's failure to prudently manage its UOG assets.[189] PG&E respectfully suggests that no such conflict of interest was presented. Indeed, PG&E requested that the engine manufacturer conduct the root cause analysis precisely because PG&E wanted to hold the vendor accountable for what PG&E expected to be a manufacturing defect.[190] Moreover, it is not unusual in the industry for the equipment manufacturer to do a root cause analysis of its own equipment since the manufacturer knows its equipment better than anyone else and has the fleet knowledge of other engines in operation around the world.[191] In any event, PG&E's internal Applied Technology Services organization reviewed the results of the vendor's analysis and agreed with it.[192] It is also worth noting that even though the warranty on the engines and engine components has expired, the engine manufacturer not only paid the cost of

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Tr. at p. 386, line 26 to p. 387, line 1 (ORA, Mangat).

[187] Ex. PG&E-14, Attachment at p. 21 ("These changed circumstances now make the waiver of consequential damages 'oppressive'").

[188] "Consequential damages are those that are not a direct result of an act, but a consequence of the initial act." http://definitions.uslegal.com/c/consequential-damages/

[189] Ex. DRA-1-C at p. 3-11, lines 17-20.

[190] Ex. PG&E-3 at p. 4-11, lines 9-12.

[191] Tr. at p. 308, lines 17-27 (PG&E, Bosscawen).

[192] Tr. at p. 309, lines 5-9 (PG&E, Bosscawen).

the root cause analysis, but indicated that it intends to pay a substantial portion of PG&E's claim against it.[193] For all these reasons, the assertion that the engine manufacturer had a conflict of interest is unavailing.

In summary, the Commission should reject ORA's recommended disallowance for the outage at HBGS Unit 5. The outage was caused by a mechanical defect that was not, and could not have been, known to PG&E prior to the outage. Imposing a disallowance on such facts would be unreasonable.

C. ORA's Disallowance Calculation is Flawed

If the Commission were to determine that a disallowance relating to the Unit 5 outage is appropriate (which it should not), it should still reject ORA's $87,000 figure. In arriving at its recommended disallowance amount, ORA used the total capacity of HBGS over 24 hours instead of assessing whether the energy was in fact needed economically (i.e., incrementally).[194] In addition, HBGS engines can be operated interchangeably, allowing for each engine and resource, if needed, to act as a backup to the others.[195] In the case of the Unit 5 outage, there was only one hour when another engine was not available to pick up any load that would have been needed from Unit 5.[196] PG&E calculated the replacement power associated with that one hour as *de minimis*.[197] ORA's analysis also used incorrect units. For example, ORA employed a formula with variable P-F, where P is $ per megawatt-hour and F is $ per Million British Thermal Units ("MMBtu").[198] This calculation would result in an error because it is not using consistent

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[193] Ex. PG&E-3-C at p. 4-11, lines 14-17.

[194] Ex. PG&E-3 at p. 4-14, lines 7-10.

[195] Ex. PG&E-3 at p. 4-14, lines 14-16.

[196] Tr. at p. 306, line 24 to p. 307, line 8 (PG&E, Bosscawen).

[197] Tr. at p. 307, lines 11-28 (PG&E, Bosscawen)(noting the precise dollar amount, which is confidential); Ex. DRA-2-C (Question 9, Supplement 1).

[198] EX. DRA-1-C at p. 3-16, line 21.

measuring units.[199] In order to convert the fuel price (MMBtu) to a comparable number, it is necessary to multiply the fuel price by the heat rate.[200] Using ORA's formula to calculate the disallowance with consistent units would result in a negative disallowance.[201] For all these reasons, the Commission should reject ORA's disallowance calculation for the HBGS Unit 5 outage.

VII. UTILITY-OWNED GENERATION – NUCLEAR (EXHIBIT PG&E-1, CHAPTER 6)

As discussed above, when evaluating whether PG&E prudently managed its UOG resources, it is important to consider relevant industry benchmarks. One of the most common nuclear industry benchmarks relates to a unit's capacity factor. Capacity factor is a measure of actual generation compared to potential generation. The higher the percentage, the better the performance. While the industry's benchmark capacity factor for 2012 was 86.4 percent, DCPP Unit 2's capacity factor was 96.41 percent, placing it in the first quartile nationally.[202] This is important context when considering an assertion that PG&E did not prudently manage Unit 2. If PG&E had acted imprudently or unreasonably, it is hard to imagine that it could have achieved its first quartile performance.

In any event, and as discussed below, PG&E prudently managed DCPP and acted as a reasonable manager would have with respect to the Unit 2 outage, the only outage at DCPP in 2012 for which ORA recommends a disallowance.

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[199] Ex. PG&E-3 at p. 4-15, lines 5-6.

[200] Ex. PG&E-3 at p. 4-15, lines 6-7.

[201] Ex. PG&E-3 at p. 4-15, lines 7-9; Ex. PG&E-3, Appendix C.

[202] Ex. PG&E-3 at p. 2-2, lines 15-25. On a combined basis, the capacity factor for Unit 1 and Unit 2 in 2012 was 90.2 percent which is also above the industry benchmark of 86.4 percent. Ex. PG&E-1 at p. 6-6, line 17 to p. 6-7, line 1.

A. Background of the Diablo Outage

ORA recommends a disallowance for a 4.4-day outage at DCPP Unit 2 that occurred in October, 2012.[203] On October 11, 2012, during a light rain, Unit 2 at PG&E's DCPP tripped following a flashover on the "A" Phase Coupling Capacitor Voltage Transformer ("CCVT").[204] PG&E determined that the cause of the flashover was insufficient distance along the CCVT insulator surface from the energized portion to ground (*i.e.*, "creepage distance").[205] The short creepage distance, coupled with a high level of contamination (principally salt) on the CCVT silicone polymer insulators, rendered the insulators ineffective at withstanding the applied voltage when the first rain of the season began.[206] The rain and contamination allowed for the formation of a conductive film over the surface of the insulators that would have been prevented if an adequate creepage margin had been maintained.[207] Unit 2 remained out of service for 4.4 days.

The CCVT that experienced the flashover had been installed in May, 2011[208] as part of a plant-wide program to replace the then-existing porcelain CCVTs, bushings, and lightning arrestors on the main bank transformer with silicon polymer insulators.[209] PG&E instituted the replacement program in response to a catastrophic failure of a porcelain bushing in 2008 that, upon shattering, launched shrapnel that damaged adjacent equipment and penetrated an administrative building.[210] Some porcelain pieces came to rest as much as a quarter of a mile

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[203] Ex. DRA-1 at p. 2-1, lines 15-18.

[204] Ex. DRA-1-C (Ex. 2.1, p. 3).

[205] Tr. at p. 192, lines 3-8 (PG&E, Harbor); Ex. DRA-1-C (Ex. 2.1, p. 33).

[206] *Id.*

[207] Ex. DRA-1-C (Ex. 2.1, p. 33).

[208] *Id.* at p. 16.

[209] *Id.* at p. 3.

[210] *Id.* at p. 3.

away from the transformer.[211] PG&E implemented the replacement program to improve the safety performance of the CCVTs, bushings and lightning arrestors so as to avoid future incidents and the associated potential for significant injuries.[212]

1. CCVT Design Criteria

In designing the CCVT replacement project, PG&E's engineers had to consider three principal design criteria: (1) seismic stability; (2) voltage requirements; and (3) creepage distance (*i.e.*, the total distance along an insulator surface from the energized portion to ground).[213] However, the three criteria were not equally important. Seismic stability was deemed the most critical element. Specifically, the new CCVT had to be able to withstand significant ground shaking (*i.e.*, not fall over) during an earthquake so that power could continue to flow to DCPP's safety systems.[214] A shorter CCVT is desirable for such seismic events since it is less prone to topple over.[215]

The second most important criteria was meeting the voltage requirements for the application since the CCVT affects operations of the entire plant and must perform properly.[216] It must have adequate voltage support to do so.[217]

The final criterion was creepage distance. Sufficient creepage distance was the least critical design element since the result of inadequate creepage distance is a flash to ground that, while not desirable, can be resolved relatively quickly.[218] Ideally, one would want a longer

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[211] *Id*. at p. 3; Tr. at p. 194, lines 3-15 (PG&E, Harbor).

[212] Tr. at p. 194, lines 16-22 (PG&E, Harbor).

[213] Ex. PG&E-3 at p. 2-6, lines 27-29 and p. 2-5, lines 1-2.

[214] Tr. at p. 197, lines 10-28 (PG&E, Harbor).

[215] Ex. DRA-1-C at p. 2-9, lines 5-7.

[216] Tr. at p. 198, lines 1-7 (PG&E, Harbor).

[217] *Id.*

[218] Tr. at p. 198, lines 8-27 (PG&E, Harbor).

creepage distance to decrease the likelihood of a flash to ground.[219] However, a CCVT with a longer creepage distance is not as seismically stable as a CCVT with a shorter creepage distance since, as noted above, a shorter CCVT is less likely to topple over during a seismic event.

2. CCVT Replacement Analysis

PG&E engineers conducted a replacement part evaluation to determine the appropriate design for the replacement CCVTs. As part of the evaluation, PG&E determined that there was only one commercially available product that met both the seismic criteria developed by the Electric Power Research Institute and the rated line voltage.[220] The product had a guaranteed creepage distance of 400 inches.[221]

Because the relevant industry standard, Institute of Electrical and Electronics Engineers ("IEEE") Standard C57.19.100, recommended a creepage distance of 502 inches for CCVTs in "heavy" contamination environments like DCPP, the lead engineer consulted with the vendor regarding the adequacy of the creepage distance on its one product that met both the seismic and voltage requirements of the application.[222] The vendor stated that the creepage distance of 400 inches was acceptable because polymer insulators give an equivalent or greater creepage distance factor compared to porcelain.[223] Since the old porcelain CCVT that was being replaced was believed by both PG&E and the vendor to have had a creepage distance of 435 inches (based on

[219] Ex. DRA-1-C at p. 2-9, lines 5-7.

[220] Ex. PG&E-3 at p. 2-7, lines 29-31.

[221] Ex. PG&E-3 at p. 2-7, lines 31-32.

[222] Ex. PG&E-3 at p. 2-5, lines 9-13; p. 2-7, lines 15-17; p. D-24 (Note that the 44mm/kV figure stated in the Table at p. D-24 for "heavy" contamination areas states the phase-to-phase, or line-to-line, voltage, not the "nominal line-to-ground voltage" as specified in the standard. To get the line-to-ground voltage, the phase-to-phase voltage must be divided by the square root of 3; so at a nominal voltage of 500kV, the line-to-ground voltage equals 500 kV divided by the square root of 3, which equals 289 kV. Then 44 mm/kV is multiplied by 289kV, which equals 12,716 mm, or 500 inches, rounded).

[223] Ex. PG&E-3 at p. 2-8, lines 28-30.

a design document for the old porcelain CCVT provided by the vendor), it was determined that a polymer insulator with a creepage distance of 400 inches would be adequate.[224]

The lead engineer confirmed this assessment with PG&E's principal engineer for high voltage power systems who had over 40 years of experience with PG&E in engineering and construction services.[225] The principal engineer indicated that a creepage distance of 400 inches was adequate since polymer insulators give a minimum 15 percent greater creepage distance factor compared to porcelain.[226] The lead engineer then calculated that the polymer insulator would yield an effective creepage distance of approximately 460 inches as compared to a porcelain CCVT (since 15 percent of 400 inches equals 60 inches).[227] Thus, the lead engineer believed the polymer insulators would have a comparatively greater creepage distance (460 inches) than the original porcelain CCVTs (435 inches).[228] In fact, and unbeknownst to both the lead engineer and the vendor, the original porcelain CCVT had a creepage distance of 521 inches.[229] Consequently, a creepage distance of 400 inches was insufficient for the application and resulted in the flashover event.

B. PG&E Acted as a Reasonable Manger With Regard To Unit 2

As noted above, the outage occurred because the newly-installed CCVT had insufficient distance along the insulator surface from the energized portion to ground (i.e., insufficient "creepage distance"). While ORA asserts that "PG&E's engineers did not adequately consider

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[224] Ex. PG&E-3 at p. 2-8, line 31 to p. 2-9, line 2; Tr. at p. 185, lines 5-19 (PG&E, Harbor).

[225] Ex. PG&E-3 at p. 2-10, lines 11-13.

[226] Ex. PG&E-3 at p. 2-10, lines 14-16.

[227] Ex. PG&E-3 at p. 2-10, 16-19.

[228] Ex. PG&E-3 at p. 2-10, lines 19-21. The lead engineer also considered internal PG&E design documents establishing a minimum creepage distance of 400 inches when using a composite insulator on a CCVT, as well as the fact that the minimum creepage distance reflected in IEEE Standard C57.19.100 may be reduced where composite insulators are utilized, as in the DCPP design. Ex. PG&E-3 at p. 2-9, lines 17 through p. 2-10, line 8; and at p. 2-10, lines 22-31.

[229] Ex. PG&E-3 at p. 2-9, lines 7-8.

the well-known IEEE and [International Electrotechnical Commission (IEC)] standards on the appropriate creepage distance for heavy particle contamination areas;"[230] and, further, that IEEE and IEC standards were not "considered,"[231] such assertions are incorrect. In fact, the lead engineer did consider those industry standards in accepting the reduced creepage distance for the CCVT replacement project[232]; the problem was that *there was no CCVT available from any vendor that met all three design criteria* – seismic stability, adequate electrical voltage, and creepage distance per industry-recommended standards.[233] That is because the first criterion (seismic stability) and the third criterion (maintaining creepage distance margin) were in conflict. As ORA acknowledges, "during the selection of CCVT there was a trade-off between the length that was needed for electrical purposes (the longer the better) and what was needed to meet seismic criteria (the shorter the better)."[234]

Because seismic stability and adequate voltage support were "must haves,"[235] while adhering to the industry-recommended creepage distance of 502 inches was, in contrast, not "a show stopper,"[236] it was reasonable to depart from the industry-recommended creepage distance, a recommendation which was just that – a recommendation. It was not mandatory.[237] ORA's argument that PG&E acted unreasonably in failing to adhere to the industry recommended creepage distance founders on its foundational assumption that departing from a recommended industry standard is *per se* unreasonable.[238] That is simply not the case. Here, it was reasonable

230 Ex. DRA-1-C at p. 2-8, lines 20-22.

231 Ex. DRA-1-C at p. 2-8, line 25.

232 Ex. PG&E-3 at p. 2-5, lines 3-16.

233 Ex. PG&E-3 at p. 2-7, lines 1-7.

234 Ex. DRA-1-C at p. 2-9, lines 5-7.

235 Tr. at p. 197, lines 27-28 and at p. 198, lines 6-7 (PG&E, Harbor).

236 Tr. at p. 198, line 17 (PG&E, Harbor).

237 Ex. PG&E-3 at p. 2-5, lines 19-25.

238 Ex. DRA-1-C at p. 2-6, lines 10-12 ("Based on PG&E's failure to follow industry's recommendations

for PG&E not to adhere strictly to the recommended creepage distance of 502 inches since there was no CCVT available on the market with such a long creepage distance that also met the more important design criteria of seismic stability and adequate voltage support. Indeed, it would have been unreasonable for PG&E to adhere strictly to the recommended 502 inches of creepage distance at the expense of seismic stability and/or adequate voltage support.

Furthermore, it was reasonable to depart from the recommended creepage distance of 502 inches because the lead engineer believed that 400 inches of creepage distance was sufficient for the application. As discussed above, the lead engineer believed that the old porcelain CCVT had a creepage distance of 435 inches, and since the new CCVT was made of a superior polymer material that yielded a 15% greater creepage margin over porcelain, 400 inches would be more than adequate. The lead engineer confirmed his understanding with the vendor and with internal PG&E experts. As it turned out, the lead engineer's belief, as well as the vendor's belief, that the old porcelain CCVT had a creepage distance of 435 inches, was incorrect. In fact, it had a creepage distance of 521 inches, as reflected in a mechanical drawing for the unit.[239] However, it was reasonable for the lead engineer to rely on the standard technical data *supplied by the vendor* for the old porcelain CCVT, which showed a creepage distance of 435 inches, since it is not customary for vendors to supply two separate design documents with conflicting information.[240] Indeed, such an occurrence is extremely uncommon.[241] PG&E, and others in the industry, expect documents provided by vendors to be accurate.[242] Such reliance is reasonable

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for creepage distance in areas of heavy or very heavy contamination, DRA found that PG&E did not act prudently and in accordance with the reasonable manager standard").

[239] Ex. PG&E-3 at p. 2-9, lines 7-8.

[240] Ex. PG&E-3 at p. 2-9, lines 9-11.

[241] Tr. at p. 201, lines 13-21 (PG&E, Harbor).

[242] Tr. at p. 202, lines 21-26 (PG&E, Harbor).

since customers are not expected to independently verify the product information provided by the vendor.[243]

ORA also asserts that PG&E should have independently verified the capability of polymer insulators "to ensure the assumptions were appropriately conservative and consistent with recommended IEEE and IEC codes and standards," and then validated the assumptions through analysis or testing.[244] For support, ORA states that "PG&E's Root Cause Evaluation Report correctly concluded that the failure to conduct a thorough independent verification and validation of the assumptions regarding capability of silicone polymer insulators was inconsistent with INPO 10-005, Principle 4…," and that "[h]ad PG&E performed testing on polymer insulators, its engineers would have noticed that the creepage distance was either simply too short and/or needed to be longer because the assumptions of polymer insulators' capability in heavy contamination environments were too optimistic."[245]

ORA's citation to the Root Cause Evaluation ("RCE") is misplaced. Nowhere in the RCE does it state that PG&E should have performed its own testing on polymer insulators and that such failure constituted a violation of INPO 10-005, Principle 4.[246] Instead, the issue identified in the RCE concerned the *failure to document* the consistency of certain assumptions with codes and standards.[247] Again, nowhere in the final RCE does it state that PG&E should have conducted independent hydrophobicity testing of the polymer insulators.[248] Such an omission is not surprising since it is not industry practice to perform independent testing of materials guaranteed by a vendor, particularly where there is no reason to suspect that the

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[243] *Id*.

[244] Ex. DRA-1-C at p. 2-7, lines 26-30.

[245] Ex. DRA-1-C at p. 2-7, line 30 to p. 2-8, line 6.

[246] Ex. PG&E-3 at p. 2-12, line 27 to p. 2-13, line 17.

[247] Ex. PG&E-3 at p. 2-13, lines 11-13.

[248] Ex. PG&E-3 at p. 2-13, lines 13-15.

materials will not perform as designed and guaranteed by the vendor.[249] In any event, the polymer material did perform as designed, according to independent tests conducted by a third-party expert hired by PG&E to assist in preparation of the RCE.[250]

In short, PG&E acknowledges that the outage at Unit 2 occurred because the newly-installed CCVT did not have sufficient creepage distance. However, given the totality of the circumstances, and based on the facts available at the time, it is clear that PG&E's decision to accept a CCVT with 400 inches of creepage distance was reasonable. To assert otherwise is to hold PG&E to an "infallible manager" standard that can never be met, does not comport with Commission decisions, and is itself unreasonable.

VIII. DIABLO CANYON SEISMIC STUDIES (EXHIBIT PG&E-1, CHAPTER 7)

In Decision 12-09-008, the Commission authorized PG&E to record in the DCSSBA, and recover in rates, its actual costs of implementing the Diablo Canyon seismic activities, up to $64.25 million.[251] The Commission directed that costs incurred and recorded in the DCSSBA be recovered in PG&E's annual ERRA account proceedings.[252] The actual costs for the Diablo Canyon seismic studies activities recorded in the DCSSBA as of December 31, 2012 were $39.91 million.[253] Because $14.41 million of that total has already been recovered in rates, PG&E through the instant application is requesting authority to transfer the balance of $25.50 million from the DCSSBA to the utility generation balancing account.[254]

PG&E has met its burden of proof with respect to the recovery of these costs, which, as stated by the Commission, is to "provide support for the amounts actually incurred and recorded

[249] Ex. PG&E-3 at p. 2-12, lines 20-26.

[250] Ex. PG&E-3 at p. 2-13, lines 15-17; Tr. at p. 190, line 8 to p. 191, line 3 (PG&E, Harbor).

[251] D.12-09-008, OP 1.

[252] D.12-09-008, OP 4.

[253] Ex. PG&E-1 at p. 7-1, lines 24-26; Ex. PG&E-2, p. 2.

[254] Ex. PG&E-1 at p. 7-2, lines 19-28; Ex. PG&E-2, p. 2.

in the DCSSBA" and to demonstrate that such costs "are consistent with PG&E's request" in its seismic studies application (A.10-01-014).[255]

Of the $39.91 million recorded in the DCSSBA as of December 31, 2012, ORA objects to PG&E's recovery of $3.76 million related to the performance of three dimensional ("3-D") high energy seismic surveys ("HESS"). These specific costs were incurred by PG&E to contract for the research vessel needed to perform the 3-D HESS as well as to perform nuclear quality assurance ("NQA") procedures with respect to the vessel to certify that the seismic data acquisition equipment to be used on the vessel met NQA standards. ORA states that "Except for the Offshore 3-D HESS, DRA found no other exceptions to the recovery requirements. The remaining entries in the DCSS Balancing Account are appropriate, correctly stated, and in compliance with Commission decisions."[256]

ORA objects to the recovery of these costs as "unproductive and of no benefit whatsoever to seismic studies or to ratepayers,"[257] because PG&E did not perform the 3-D HESS since the California Coastal Commission ("CCC") ultimately denied a necessary permit for it. ORA asserts that "there should have been a reasonable expectation the CCC may deny such authorization."[258] Because it was foreseeable, ORA asserts, that the CCC might deny PG&E's permit application, PG&E should not have contracted for the research vessel prior to receiving the permit from the CCC.

As an initial matter, ORA's assertion that the costs incurred by PG&E in contracting for the research vessel were "unproductive and of no benefit whatsoever to seismic studies or to ratepayers,"[259] does not state the proper standard of review for recovery of the contracting costs.

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[255] D.12-09-008, OP 4.

[256] Ex. DRA-1, p. 6-5, lines 24-26.

[257] Ex. DRA-1, p. 6-5, lines 2-3.

[258] Ex. DRA-1, p. 6-4, lines 15-16.

[259] Ex. DRA-1, p. 6-5, lines 2-3.

As noted above, PG&E is required in its ERRA application to "provide support for the amounts actually incurred and recorded in the DCSSBA" and to demonstrate that such costs "are consistent with PG&E's request" in its seismic studies application (A.10-01-014).[260] PG&E need not demonstrate that the costs were "productive" or of "benefit to ratepayers."

Moreover, ORA's argument, which fails to acknowledge the highly complex regulatory framework governing the issuance of permits for the 3-D HESS, is overly simplistic and should be rejected by the Commission. Specifically, ORA's argument fails to acknowledge the numerous logistical, scheduling, timing and permitting challenges inherent in a project as complex as the 3-D HESS. ORA's simple assertion that PG&E should have anticipated the CCC would deny PG&E's permit application is made in a factual vacuum with no understanding, acknowledgement or appreciation of all that preceded the CCC's decision to deny the permit.

ORA's argument also fails to acknowledge that the state agency charged under state law with conducting the environmental analysis for the project, the California State Lands Commission ("CSLC"), approved the project and issued to PG&E a permit to conduct the 3-D HESS. While the CCC cited several environmental concerns in denying PG&E's permit application, those environmental issues were primarily within the purview of the CSLC, which, again, had already approved the project after conducting an exhaustive environmental analysis.[261] Consequently, PG&E had a reasonable expectation that the CCC would likewise give its approval to the project.

[260] D.12-09-008, OP 4.

[261] Tr. at p. 477, line 23 to p. 479, line 4 (PG&E, Nishenko); Ex. ORA-7 at p. 52 ("The [California Coastal] Commission finds that, for the reasons discussed above, the proposed project would result in adverse impacts to marine resources and the biological productivity of coastal waters. These adverse effects include behavioral harassment and potentially injurious physiological effect on large numbers of marine mammals; the loss of fish and invertebrate eggs and larvae; the injury, disturbance, and loss of adult fish and invertebrates; and damage to marine protected areas").

Finally, ORA's argument fails to acknowledge that had PG&E failed to contract for the vessel in advance of receiving the permit from the CCC, it could have incurred an additional $2 million in costs to bring the vessel, which was already on the West Coast, back to the West Coast from somewhere else around the world, assuming the vessel was still available.

To fully comprehend the inadequacies of ORA's argument is, it is first necessary to understand the complex regulatory and permitting framework associated with the 3D HESS project.

A. The Regulatory and Permitting Framework

The most significant element of the permitting process for the 3-D HESS involved compliance with the California Environmental Quality Act, or CEQA. In brief, CEQA requires state and local agencies to follow a protocol of analysis and public disclosure of environmental impacts of proposed, non-exempt, projects and adopt all feasible measures to mitigate those impacts.[262] A public agency must comply with CEQA when it issues a discretionary permit that may cause either a direct physical change in the environment or a reasonably foreseeable indirect change in the environment.[263]

The scope of environmental review mandated by CEQA is extremely broad. Among the potential project impacts an agency must evaluate in its environmental report are impacts to the following: aesthetics, air quality, biological resources (both terrestrial and marine), cultural resources, geology and soils, greenhouse gas emissions, public services, water quality, land use, recreation, noise, and traffic and transportation.[264] Experts in all of these areas perform the various analyses for the agency which states its conclusions and any required mitigation measures in an Environmental Impact Report, or EIR (if it is determined that the project may

[262] *See generally* Pub. Res. Code § 21000 et seq.

[263] *Id.*

[264] CEQA Appendix G.

have a significant effect on the environment). Where, as here, a project is to be approved by more than one agency, a CEQA "lead agency" is designated, which agency prepares the EIR for a project. The CEQA "lead agency" is the agency "which has the principal responsibility for carrying out or approving a project."[265] Importantly, the CSLC was the CEQA "lead agency" for the 3-D HESS project and, consequently, was required to conduct the environmental analysis and to prepare the EIR for the project.[266]

The level of review mandated by CEQA for a project as complex as the 3-D HESS project is substantial.[267] The EIR prepared for the project by the CSLC lists 17 pages of federal, state and local laws and regulations that were implicated by the project and that relate in some way to the various resource areas listed above.[268] The EIR further notes that permits and/or approvals were required from 14 different federal, state and local agencies.[269]

PG&E had to interface with all of these agencies and seek to resolve with them a myriad of extremely complex regulatory issues before submitting its permit application to the CSLC in order to be able to file a complete application.[270] Indeed, it took PG&E approximately one year to prepare the permit application, which consisted of several thousand pages of documents.[271] PG&E also needed to work with the various agencies of jurisdiction after submitting its permit application to address their concerns with the project.[272] In short, the permitting process for a

[265] Pub. Res. Code § 21067.

[266] Ex. PG&E-3 at p. 7-2, line 42 to p. 7-3, line 2.

[267] Ex. PG&E-3 at p. 7-3, lines 3-4.

[268] Ex. PG&E-3 at p. F-35 to F-51.

[269] Ex. PG&E-3 at p. F-33 to F-34.

[270] Ex. PG&E-3 at p. 7-3, lines 30-33.

[271] Ex. PG&E-3 at p. 7-3, lines 33-35.

[272] Ex. PG&E-3 at p. 7-3, lines 35-37.

project like the 3-D HESS is extraordinarily complex, with innumerable moving parts that must be managed.

B. Prudent Project Management Often Requires Significant Pre-Permit Expenditures[273]

As discussed above, PG&E needed to undertake significant work prior to receiving all of the required permits for the 3-D HESS project. This is not atypical. Indeed, even for the most straightforward projects it is typical to incur substantial costs prior to receiving a permit. For example, in building a house, prior to submitting a permit application to the housing department it is necessary to hire an architect, contractor, surveyor, structural engineer, perform biological and cultural surveys, prepare designs and drawings, and meet with the local zoning board, local officials, and utilities. In other words, prudent project management requires that certain expenditures be made prior to project approval in order to make approval more likely (i.e., by allowing for the submission of a complete permit application) and also to allow for the project to be completed as cost-effectively as possible and within applicable time constraints. Conversely, deferring all significant expenditures to after approvals are obtained is not prudent project management. That is particularly true of a project as complex as the 3-D HESS since the level of pre-approval planning, design and logistics necessary is exponentially greater than for a typical construction project.

In addition, for any project there are "critical path" items that effectively set the schedule for the rest of the project; items that without certainty as to their availability and timing, no other project elements can be planned. Prudent project management recognizes the need to address "critical path" items at the outset in order to be able to establish a realistic project schedule and project budget. As discussed herein, contracting for the research vessel was such a critical path item for the 3-D HESS.

[273] The following discussion is taken from Ex. PG&E-3 at p. 7-4, lines 3-26.

1. Time Was of the Essence for Completing the 3-D HESS

PG&E had proposed conducting the 3-D HESS project during the months of October through December 2012 in order to mitigate impacts to whales and the commercial fishing industry.[274] This timing was critical as the CSLC's approval of the project was predicated on it.[275] In addition, it was important to try and avoid having the studies continue into a second year which the EIR concluded would result in additional adverse impacts.[276] In short, PG&E needed to try and complete the project within a very narrow time window.

Furthermore, because the 3-D HESS was part of a larger project to ensure the safety of a nuclear facility, it was imperative that it be performed expeditiously. As PG&E witness Nishenko testified at hearing, "There was a great deal of concern on the part of the state and all state agencies that this application be expedited through all of the permit-granting agencies, given the situation that we were addressing."[277] The Fukushima Daiichi disaster in March 2011 added an additional sense of urgency to the project given the concerns it raised regarding the safety of nuclear facilities along coastal zones.[278] As Dr. Nishenko testified at hearing, in light of the Fukushima Daiichi disaster "there was an expectation that PG&E would start doing this work as soon as possible."[279]

PG&E initiated its 3-D HESS permitting work in January 2011 when it signed a contract with Fugro Consultants, Inc. to perform NQA activities.[280] PG&E also issued a request for

[274] Ex. PG&E-3 at p. 7-3, lines 38-41.

[275] Ex. PG&E-3 at p. 7-3, lines 41-42.

[276] Ex. PG&E-3 at p. 7-3, line 42 to p. 7-4, line 1.

[277] Tr. at p. 460, line 24 to p. 461, line 1 (PG&E, Nishenko).

[278] Tr. at p. 473, lines 4-13 (PG&E, Nishensko).

[279] Tr. at p. 474, lines 5-7 (PG&E, Nishenko).

[280] Ex. ORA-6, Attachment 1; Tr. at p. 452, line 21 to p. 453, line 10 (PG&E, Ferre).

proposals in 2011 for a research vessel, ultimately selecting Columbia University, and began working with Columbia University in the Fall of 2011.[281]

PG&E filed applications for all necessary federal and state permits by the end of April 2012.[282] Among the required permits was a Geophysical Survey Permit, issued by the CSLC, and a Coastal Development Permit, issued by the CCC. As discussed above, the CSLC was the "lead agency" under CEQA and was tasked with conducting the environmental analysis and preparing an EIR for the project. The EIR prepared by the CSLC was voluminous, comprising multiple volumes, and was several inches thick.[283]

The CCC had substantial input into the final EIR. In preparing the final EIR, the CSLC considered, and responded exhaustively to, comments submitted by the CCC, issuing a 21-page document addressing them.[284] The CCC itself acknowledged that its staff "coordinated closely with CSLC staff throughout the review process and during the development of the EIR."[285] There was even a member of the CCC on the independent peer review panel established by the Commission to conduct a peer review of the seismic studies, including independently reviewing and commenting on the study plan.[286]

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[281] Tr. at p. 463, line 28 to p. 464, line 4. Note that PG&E did not sign a contract with Columbia University until November 1, 2012, and made its first payment to Columbia University the next day, on November 2, 2012. Ex. ORA-5; Tr. at p. 447, lines 2-16 (PG&E, Nishenko); Tr. at p. 448, lines 19-21 (PG&E, Nishenko). However, as noted above, PG&E began working with Columbia University in the Fall of 2011, and the November 2, 2012 payment "constituted work that started way before." Tr. at p. 463, lines 14-16 (PG&E, Ferre). PG&E could not rightly have withheld payment to Columbia University pending a favorable determination by the CCC on PG&E's Coastal Development Permit application. Tr. at p. 463, lines 25-28 (PG&E, Nishenko)("I think there was an ethical obligation at that point because we had been working with Columbia University").

[282] Ex. PG&E-1 at p. 7-4, lines 19-20.

[283] Ex. PG&E-3 at p. 7-7, lines 19-21.

[284] Ex. PG&E-3 at p. F-1 to F-30.

[285] Ex. ORA-7 at p. 18.

[286] D.10-08-003 at pp. 9-10; Tr. at p. 476, lines 4-13 (PG&E, Ferre).

In August 2012, the CSLC approved the Geophysical Survey Permit for the 3-D HESS.[287] However, the CCC did not take up PG&E's Coastal Development Permit application until after the CSLC authorized the Geophysical Survey Permit in August, 2012.[288] PG&E responded to several requests for additional information made by the CCC in the August to October, 2012 timeframe.[289] Notwithstanding PG&E's best efforts, on November 2, 2012, CCC staff issued a report recommending that the CCC deny PG&E's permit application, primarily on environmental grounds.[290] PG&E did not have any advance notification that CCC staff would recommend denial of the permit.[291] On November, 12, 2012, the full Commission adopted staff's recommendation and denied PG&E's Coastal Development Permit application.[292]

2. PG&E Had a Reasonable Expectation that the CCC Would Issue a Coastal Development Permit for the 3-D HESS

In light of the comprehensive environmental analysis performed by the CSLC, which analysis involved substantial input by, and coordination with, the CCC, it was reasonable for PG&E to assume that the CCC would authorize PG&E to conduct the 3-D HESS. Indeed, once the CSLC approved the project in August 2012, it was even more reasonable to assume that PG&E would receive the permit from the CCC since the CSLC was the lead agency for environmental review under CEQA and, as such, had "the principal responsibility for carrying out or approving a project."[293] Indeed, the CSLC had completed a rigorous environmental

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[287] Ex. PG&E-1 at p. 7-5, line 3.

[288] Ex. PG&E-1at p. 7-5, lines 8-9.

[289] Ex. PG&E-1at p. 7-5, lines 10-12; Tr. at p. 459, lines 1-9 (PG&E, Nishenko).

[290] Ex. ORA-7.

[291] Tr. at p. 461, line 25 to p. 462, line 15 (PG&E, Nishenko).

[292] Ex. ORA-7.

[293] Pub. Res. Code § 21067. *See also* Tr. at p. 476, lines 4-13 (PG&E, Ferre)("So in our feeling, when the permit was approved by the State Lands Commission - - the geophysical survey permit was approved in August. That had a lot of input already by the Coastal Commission. We had a member of the Coastal Commission on the independent peer review panel. There was really - - we felt it was going to go. So we did everything that was necessary to get it ready to go.").

review of many of the same issues that the CCC was assessing. The final EIR was literally thousands of pages long and incorporated input from several public hearings. The CSLC also responded substantively to all of the numerous public comments it received on the draft EIR (again, including comments submitted by the CCC). It was certainly reasonable to assume that the CCC would credit the rigorous and comprehensive review undertaken by the CEQA lead agency. In fact, CEQA requires so-called "responsible agencies" (i.e., agencies other than the "lead agency"), such as the CCC in this case, to "certify that its decision making body reviewed and considered the information contained in the EIR."[294] It was reasonable to assume that the CCC would comply with this directive, consider the rigorous analysis contained in the EIR, and reach a similar result as the CSLC. Furthermore, PG&E remained engaged throughout the permitting process with CCC staff regarding the scope and duration of the project, answering every question that was posed.[295] The proposed project also had the support of the California Public Utilities Commission, the PUC Independent Peer Review Panel, the California Energy Commission, and the Alfred E. Alquist Seismic Safety Commission.[296]

For all these reasons, PG&E had a reasonable expectation that the CCC would authorize PG&E to conduct the Offshore 3-D HESS. ORA's unsupported assertion to the contrary ignores literally years of work dedicated to the permitting process by PG&E, working hand-in-hand with all of the agencies of jurisdiction (including the CCC), as well as the fact that the state agency actually charged with performing the environmental review of the project under CEQA approved it. That the CCC would take a different course and reject the Coastal Development Permit application was not reasonably foreseeable, as ORA asserts. While it was, of course,

[294] 14 C.C.R. § 15050(b).

[295] *See, e.g.* Ex. ORA-9; Tr. at p. 470, line 4 to p. 471, line 9 (PG&E, Nishenko); Tr. at p. 459, lines 1-9 (PG&E, Nishenko).

[296] Ex. PG&E-3 at p. 7-5, lines 12-17.

theoretically possible the CCC would do so, it was not reasonably foreseeable to PG&E that it would do so.

3. The Research Vessel Costs were Reasonably Incurred

Equally unavailing is ORA's assertion that PG&E should have waited until it received the Coastal Development Permit from the CCC before contracting for the research vessel.

PG&E's contracting of the survey vessel is a prime example of a "critical path" item.[297] As the CSLC recognized, "Survey vessels are specialty vessels that operate around the world and may be contracted months or years in advance."[298] Had PG&E waited until permit issuance to contract for the survey vessel, it would have been impossible to complete the project on schedule and within budget since the window of opportunity presented by the fact that the research vessel was already on the West Coast, with time-consuming NQA calibrations and certifications already complete, would have been lost.[299] Project delays could literally have been measured in years.[300] Moreover, the CSLC's approval of the project was predicated on PG&E contracting with the specific vessel since the agency's analysis of several issues (e.g., air emissions, sound source levels) assumed PG&E would use that specific vessel and equipment.[301] If PG&E had to use another research vessel because the Columbia University vessel had become unavailable in the interim, the permitting process likely would have had to have been re-opened at considerable additional cost and delay.[302]

[297] Ex. PG&E-3 at p. 7-7, lines 31-32.

[298] Ex. PG&E-3 at p. 7-7, line 32 to p. 7-8, line 2; Ex. PG&E-3, p. F-57.

[299] Ex. PG&E-3 at p. 7-8, lines 2-10.

[300] Ex. PG&E-3 at p. 7-8, lines 4-5.

[301] Ex. PG&E-3 at p. 7-8, lines 10-13.

[302] Ex. PG&E-3 at p. 7-8, lines 13-16.

Finally, the vessel at issue was already scheduled to be on the West Coast in advance of the October-December window.[303] Had PG&E not initiated the contracting process in advance of receiving the permit from the CCC, and had the permit ultimately been issued by the CCC, PG&E would have incurred approximately $2 million to transit the vessel to the West Coast, depending upon the precise location of the vessel at the time of transit.[304]

ORA's overly simplistic assertion that PG&E should have waited until it received the Coastal Development Permit from the CCC before contracting for the research vessel does not acknowledge, let alone address, any of the significant permitting, scheduling and cost issues implicated by the assertion. Accordingly, the Commission should reject it.

In sum, PG&E has met its burden of proof in "provid[ing] support for the amounts actually incurred and recorded in the DCSSBA" and in demonstrating that such costs "are consistent with PG&E's request" in its seismic studies application (A.10-01-014).[305] ORA's assertion that the costs incurred by PG&E in contracting for the research vessel were "unproductive and of no benefit whatsoever to seismic studies or to ratepayers,"[306] does not state the proper standard of review for recovery of the contracting costs, and, moreover, fails to acknowledge the highly complex regulatory framework governing the issuance of permits for the 3-D HESS. Consequently, the Commission should grant PG&E's request to transfer $25.50 million (including $3.76 million for the 3-D HESS) from the DCSSBA to the utility generation balancing account.

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[303] Ex. PG&E-3 at p. 7-8, lines 5-7.

[304] Ex. PG&E-3 at p. 7-8, lines 17-28.

[305] D.12-09-008, OP 4.

[306] Ex. ORA-1, p. 6-5, lines 2-3.

IX. GENERATION FUELS COSTS, STARS ALLIANCE COSTS, AND GAS HEDGING (EXHIBIT PG&E-1, CHAPTER 8)

Chapter 8 of PG&E's Prepared Testimony addresses generation fuels costs, costs related to the STARS Alliance, and gas hedging costs. This section of PG&E's opening brief addresses fuel costs, STARS Alliance costs and gas hedging, including the non-compliant gas hedging transactions at issue in Phase 2 of the proceeding.

A. Generation Fuel Costs and STARS Alliance Costs

During the record period, PG&E procured different types of fuel for its UOG facilities, as well as fuel for third-party contracts. PG&E's fuel purchases included natural gas (including both the natural gas commodity and transportation, storage and other services), distillate, water and nuclear fuel. Each of these fuel purchases is described below.

PG&E purchased natural gas commodity and services for its UOG facilities and tolling agreements (*i.e.*, contracts under which PG&E provides the fuel to a generator and the generator provides electricity to PG&E).[307] PG&E reported its gas commodity transactions in its Quarterly Compliance Reports ("QCRs") and described them in detail in its Prepared Testimony.[308] These transactions were also the subject of gas supply plans that were reviewed with the PRG during the record period.[309] In addition to its gas commodity purchases, PG&E received revenue related to gas liquid extraction which occurs in Canada[310] and gas transportation and other gas services.[311] PG&E also purchases natural gas commodity and services for the California Department of Water Resources ("CDWR") contracts allocated to PG&E.[312] PG&E's purchases

[307] Ex. PG&E-1 at p. 8-2, line 2 to p. 8-4, line 1.

[308] Ex. PG&E-1 at p. 8-4, line 2 to p. 8-9, line 11.

[309] Ex. PG&E-1 at p. 8-5, lines 17-18.

[310] Ex. PG&E-1 at p. 8-9, line 12 to p. 8-10, line 6.

[311] Ex. PG&E-1 at p. 8-10, line 7 to p. 8-15, line 3.

[312] Ex. PG&E-1 at p. 8-15, line 9 to p. 8-16, line 9.

were consistent with the CDWR Operating Agreement and involved both commodity and transportation and other services.[313]

PG&E also procured distillate fuel during the record period as a backup fuel for HBGS.[314] These purchases were relatively small. HBGS uses distillate as a pilot fuel and as a backup in case there is an interruption in natural gas service. PG&E also purchases a small amount of water for its hydro powerhouses.[315] These purchases total less than $2 million, but are cost-effective as it allows PG&E to generate additional, below-market hydroelectric energy. Finally, PG&E purchases nuclear fuel and incurs nuclear fuel carry costs for Diablo Canyon.[316] These purchases are consistent with PG&E's Commission-approved Nuclear Fuel Procurement Plan that is a part of the BPP.[317]

PG&E's fuel purchasing activities during the record period were consistent with the BPP and/or PG&E's Commission-approved CDWR Gas Supply Plan.[318] ORA did not raise any concerns regarding PG&E's fuel purchases in its testimony or at the hearing. Based on the undisputed evidence provided in PG&E's Prepared Testimony, PG&E requests that the Commission determine that PG&E prudently administered its fuel contracts.

In addition to fuel purchases, PG&E also incurred costs during the record period as a result of its participation in the STARS Alliance. The STARS Alliance includes utilities that operate nuclear facilities and is intended to reduce costs and increase efficiency for members.[319] In D.12-05-010, the Commission directed PG&E to report STARS Alliance costs in the ERRA

[313] Ex. PG&E-1 at p. 8-16, line 10 to p. 8-17, line 29.

[314] Ex. PG&E-1 at p. 8-22, lines 15-22.

[315] Ex. PG&E-1 at p. 8-22, line 23 to p. 8-23, line 10.

[316] Ex. PG&E-1 at p. 8-23, line 11 to p. 8-24, line 30.

[317] Ex. PG&E-1 at p. 8-23, lines 12-14.

[318] Ex. PG&E-1 at p. 8-1, lines 13-19.

[319] Ex. PG&E-1 at p. 8-24, line 31 to p. 8-25, line 18.

Compliance proceedings.[320] During the record period, PG&E incurred limited costs for its participation in the STARS Alliance and received substantial benefits in terms of reduced costs.[321] PG&E is not seeking any Commission decision in this proceeding regarding the STARS Alliance, those issues are addressed in the General Rate Case.[322] However, PG&E is reporting these costs to comply with D.12-05-010.

B. Hedging Activities

PG&E had two Commission-approved hedging plans in effect during 2012. During the first eleven days of January 2012, the hedging plan approved in 2006 was in effect. On January 12, 2012, PG&E implemented the Hedging Plan approved by the Commission in D.12-01-033.[323] The Hedging Plan implemented on January 12th included an operating limit that had not been included in the 2006 hedging plan.[324] When PG&E updated its electronic hedging implementation model, which acts as a control for PG&E's hedging activities, the new operating target was inadvertently not included and thus, during the record period, PG&E executed forty-eight (48) transactions that exceeded this operating target.[325]

PG&E initially identified non-compliant hedging transactions that occurred in 2013 during an internal review. As a result of this discovery, PG&E promptly reviewed all 2012 and 2013 transactions and discovered the forty-eight (48) non-complaint transactions that occurred during the record period.[326] Some of the transactions had already settled at the time of discovery. However, eleven (11) of these transactions were still open and subject to market fluctuations.[327]

[320] D.12-05-010, OP 3.

[321] Ex. PG&E-1 at p. 8-25, lines 12-14.

[322] Ex. PG&E-1 at p. 8-25, lines 16-18.

[323] Ex. PG&E-16 at p. 2, n. 2.

[324] Tr. at p. 409, lines 19 to p. 410, line 10 (PG&E, Koszalka).

[325] Ex. PG&E-16 at p. 2, lines 11-15.

[326] Ex. PG&E-16 at p. 1, line 20 to p. 2, line 10.

[327] Ex. PG&E-16 at p. 3, lines 3-11.

Because the eleven (11) open transactions were subject to market risk, and could potentially result in a loss, PG&E promptly entered into four (4) offsetting transactions.[328] The forty-eight (48) non-complaint transactions and four (4) offsetting transactions resulted in a net gain of $416,122.[329] After addressing the immediate transactions, PG&E put in place a number of controls to prevent the reoccurrence of this kind of situation, and has implemented new reporting protocols that will result in PG&E providing hedging transaction reports in its QCRs.[330] In this proceeding, PG&E is requesting that the Commission approve: (1) the forty-eight (48) non-compliant transactions; (2) the four (4) offsetting transactions; and (3) the inclusion of the $416,122 net gain in the ERRA balancing account.

ORA reviewed PG&E's Phase 2 concerning the non-compliant hedging transactions and conducted additional discovery on this issue. ORA did not recommend a disallowance and agreed that the net gain from the hedging transactions should be included in ERRA. Moreover, at the hearing, ORA witness Ravinder Mangat testified that he believed that PG&E made the right decision entering into the four (4) offset transactions as promptly as PG&E did because these offsetting transactions were intended to bring PG&E back in compliance and to protect customers.[331]

ORA did express some concerns, however, regarding the timeliness of PG&E's notification to the Commission regarding the non-compliant transactions.[332] To address this concern, ORA proposed three corrective actions regarding reporting of any future non-compliant

[328] Ex. PG&E-16 at p. 3, lines 4-7; Tr. at p. 411, lines 13-28 (PG&E, Koszalka).

[329] Ex. PG&E-16 at p. 3 (transaction summary table).

[330] Ex. PG&E-16 at p. 3, line 19 to p. 4, line 27.

[331] Tr. at p. 430, line 13 to p. 432, line 28 (ORA, Mangat).

[332] Ex. ORA-10 at p. 3, lines 20-29.

activity.[333] In its Phase 2 rebuttal testimony, PG&E recommended a few clarifications and modifications to ORA's proposed corrective actions.[334]

At the hearing, ORA's witness, agreed with two of the three revisions proposed by PG&E in its rebuttal testimony. Specifically, Mr. Mangat agreed that any reporting requirement for non-compliant transactions should not arise until PG&E has discovered and verified the non-compliance and agreed that PG&E should provide notice of non-compliance to the Energy Division.[335]

ORA's witness did not agree, however, with the notification timing proposed by PG&E. During the hearing, Mr. Mangat suggested that notice of non-compliance be provided within ten (10) business days of the discovery and verification and that a corrective action plan be provided within thirty (30) business days[336]; PG&E recommends that notice be provided within fifteen (15) business days and a corrective action plan be provided within forty-five (45) days. ORA has not provided any basis for its proposed timing. As PG&E witness Koszalka explained in his rebuttal testimony, reviewing and correcting non-compliant transactions and coming up with a corrective action plan can be complex and the timing proposed by ORA to take these actions is unnecessarily short.[337] Given this, PG&E's proposal for reporting any future non-compliant transactions should be adopted.[338]

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[333] Ex. ORA-10 at p. 5, line 26 to p. 6, line 2.

[334] Ex. PG&E-17 at p. 1, line 22 to p. 3, line 9.

[335] Tr. at p. 427, line 2 to p. 428, line 10 (ORA, Mangat).

[336] Tr. at p. 428, line 13 to p. 429, line 5 (ORA, Mangat).

[337] Ex. PG&E-17 at p. 2, lines 16-32.

[338] Ex. PG&E-17 at p. 3, lines 1-9.

X. GREENHOUSE GAS COMPLIANCE INSTRUMENT PROCUREMENT (EXHIBIT PG&E-1, CHAPTER 9)

With regard to greenhouse gas ("GHG") compliance instrument procurement, the Scoping Memo clarified that the issue in this proceeding is whether PG&E's procurement complied with its bundled procurement plan.[339] In D.12-04-046, the Commission authorized PG&E and the other California utilities to procure the allowances and offsets necessary for each of the utilities to comply with their respective GHG compliance obligations.[340] The Commission subsequently approved an appendix to PG&E's bundled procurement plan that included PG&E's GHG procurement strategy consistent with the Commission's direction in D.12-04-046.[341]

The California Air Resources Board ("CARB") held its first auction for GHG allowances in November 2012. During the record period at issue in this proceeding, PG&E implemented its BPP procurement strategy for GHG compliance instruments, as described in more detail in a confidential portion of PG&E's testimony.[342] In its testimony, ORA did not raise any issues regarding PG&E's GHG procurement.[343] Based on PG&E's undisputed testimony, the Commission should find that PG&E's GHG compliance instrument procurement was consistent with its approved BPP during the record period.[344]

XI. CONTRACT ADMINISTRATION (EXHIBIT PG&E-1, CHAPTER 10)

PG&E administers hundreds of power contracts to ensure a reliable and affordable source of electricity for its bundled customers. During the record period, PG&E purchased through these contracts 32,407 gigawatt-hours ("GWh") of energy at a total cost of approximately $2.242

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339 Scoping Memo at pp. 8-9.

340 D.12-04-046, OP 8; Ex. PG&E-1 at p. 9-2, lines 5-12.

341 Resolution E-4544; Ex. PG&E-1 at p. 9-2, lines 12-19.

342 Ex. PG&E-1 at p. 9-2, line 29 to p. 9-3, line 7.

343 Ex. DRA-1 (Memorandum) at p. 2 (DR contract administration not covered in ORA's testimony).

344 Scoping Memo at p. 10 (Item #8).

billion.[345] PG&E's Prepared Testimony included more than 80 pages addressing contract administration issues, including a detailed discussion of PG&E's contract administration processes, specific administration details regarding various types of contracts (*e.g.*, CDWR, renewable, QF, etc.), and detailed tables identifying each contract that had been executed, amended or terminated during the record period. PG&E also provided in its Prepared Testimony a table of transactions that had been listed in PG&E's 2012 Quarterly Compliance Reports that PG&E is requesting approval of in this proceeding.[346] Table 10-22 identifies each transaction and includes the execution date, the counterparty, and a description of the transaction. PG&E provided a copy of each transaction to ORA in discovery. In addition, PG&E's testimony described many of the transactions listed in Table 10-22.

In its testimony, ORA did not raise any concerns generally about PG&E's contract administration during the record period, and only identified three specific transactions that ORA claimed were imprudent. The three transactions identified by ORA were with Amedee Geothermal Venture 1 ("Amedee"), Wendel Energy Operations 1 ("Wendel"), and the University of California San Francisco ("UCSF"). PG&E addresses each of these transactions below. Based on the evidence in this proceeding, and the argument below, the Commission should find that PG&E prudently administered and managed its QF and non-QF contracts in accordance with the contracts' provisions, including the Amedee, Wendel, and UCSF transactions.[347] In addition, the Commission should approve the transactions identified in Table 10-22 of PG&E's Prepared Testimony.

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[345] Ex. PG&E-1 at p. 10-1, lines 8-12.

[346] Ex. PG&E-1 at p. 10-80, Table 10-22.

[347] Scoping Memo at p. 10 (Issue #2).

A. The Amedee Letter Agreement Is Reasonable and Prudent

Amedee is a 2.2 MW geothermal facility located in the Lassen Municipal Utilities District's ("LMUD") service territory.[348] Amedee is a QF facility that has had a contract with PG&E for more than 20 years. As a geothermal QF, deliveries from Amedee count toward meeting the Renewable Portfolio Standard ("RPS") compliance obligation established for PG&E's customers.

In 2009, LMUD changed the voltage on the line that transports energy from the Amedee facility to PG&E from a 34.5 kilo-volt ("kV") transmission line to a 12.47 kV distribution line. PG&E was notified of the voltage change, but did not make a corresponding adjustment to the Amedee meter constant. As a result, Amedee's meter indicated that it was providing more energy than was actually being provided, and thus Amedee was overpaid. As soon as PG&E discovered the meter constant issue in 2012, it promptly corrected the meter constant and sought to recover the overpayments from Amedee.[349]

During discussions regarding the overpayment, Amedee explained that return of the full amount may not be possible based on certain financial considerations.[350] These financial considerations are described in more detail in Confidential Exhibit 11-C and were independently verified by PG&E.[351] Because of these considerations, and in order to ensure the continued operation of an RPS-eligible resource, PG&E and Amedee negotiated a letter agreement that

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[348] Ex. PG&E-1 at p. 10-33, lines 14-17.

[349] Ex. PG&E-1 at p. 10-33, pp. 16-24.

[350] Ex. PG&E-5 at p. 5-2, lines 14-20 (the specific financial considerations are confidential because they involve statements by Amedee regarding its financial condition); *see also* Ex. PG&E-11-C at p. 2 (providing a more detailed, confidential discussion of financial considerations).

[351] Ex. PG&E-11-C (Response to DRA Data Request Set #2, Question 1, Item 2.3.1.1) (describing financial condition of Amedee, verification by PG&E and discussions between the parties).

provided for the return of some, but not all, of the overpayment.[352] The letter agreement also allowed PG&E to avoid costly litigation to recover the overpayment made to Amedee.[353]

The Commission has recently approved settlement agreements in which PG&E only recovered a portion of an amount owed by a QF in order to avoid the cost and uncertainties of litigation and because the QF's financial condition made full recovery unlikely.[354] The situation here is similar. Had PG&E decided to pursue collection of the full amount of the overpayment from Amedee, it would have incurred costs doing so and it is uncertain whether these amounts would have been collected. Moreover, recovering the full amount could have jeopardized the ongoing performance of a QF that provides RPS-eligible energy to PG&E's customers. PG&E prudently administered the contract with Amedee by agreeing to a letter agreement that allowed the parties to resolve the overpayment issue in a manner that reasonably reduced additional cost and uncertainty.

Finally, PG&E has initiated actions to ensure that similar metering issues do not occur again.[355] Specifically, PG&E's Energy Procurement organization has worked with the Customer Care organization, which oversees metering, to ensure that information is promptly shared between the organizations. In addition, PG&E has implemented a training program to address communications between the various departments within PG&E. The training program is ongoing and the outcome has been very positive.[356] Given the reasonableness of the letter agreement and PG&E's corrective actions, PG&E's administration of the Amedee contract was prudent and ORA's disallowance recommendation should be rejected.

[352] Ex. PG&E-3-C at p. 5-2, line 22 to p. 5-3, line 4.

[353] Ex. PG&E-1 at p. 10-33, line 33.

[354] D.12-05-026, FOF 14-15 (describing financial condition of QF and PG&E's recovery of a "modest amount" of the damages), COL 2 (describing uncertainty of litigation and associated expense)

[355] Ex. PG&E-3 at p. 5-5, line 23 to p. 5-6, line 9.

[356] Tr. p. 339, line 21 to p. 340, line 18 (PG&E, Chan).

B. The Wendel Letter Agreement Is Reasonable and Prudent

Wendel's situation was virtually identical to Amedee's situation. Wendel is a small geothermal facility (0.7 MW) located in LMUD's territory that was also impacted by the change in line voltage in 2009.[357] Like Amedee, PG&E discovered in 2012 that the meter constants for the Wendel facility had not been changed in 2009 and, as a result, Wendel had been overpaid. During discussions regarding the overpayment, Wendel explained that return of the full amount may not be possible based on certain financial considerations.[358] These financial considerations are described in more detail in Confidential Exhibit 11-C and were independently verified by PG&E.[359] Because of these considerations, and in order to ensure the continued operation of an RPS-eligible resource, PG&E and Wendel negotiated a letter agreement that provided for the return of some, but not all, of the overpayment.[360] The letter agreement also allowed PG&E to avoid costly litigation to recover the overpayment made to Wendel.[361] In addition, PG&E's corrective actions described above with regard to Amedee applying equally to Wendel. PG&E's administration of the Wendel contract was prudent and consistent with Commission precedent[362], and ORA's disallowance recommendation should be rejected.

There is one additional issue that ORA raised that is unique to Wendel. Amedee made its repayment in a single lump sum payment and thus there was no issue regarding the net present value of that payment.[363] Wendel, on the other hand, is repaying the agreed to amount over time

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[357] Ex. PG&E-1 at p. 10-33, lines 14-21.

[358] Ex. PG&E-5 at p. 5-2, lines 14-20 (the specific financial considerations are confidential because they involve statements by Wendel regarding its financial condition); *see also* Ex. PG&E-11-C (providing a more detailed, confidential discussion of financial considerations).

[359] Ex. PG&E-11-C (Response to DRA Data Request Set #2, Question 2, Item 2.3.2.1) (describing financial condition of Wendel, verification by PG&E and discussions between the parties).

[360] Ex. PG&E-3-C at p. 5-2, line 22 to p. 5-3, line 4.

[361] Ex. PG&E-1 at p. 10-33, line 33.

[362] D.12-05-026, FOF 14-15 (describing financial condition of QF and PG&E's recovery of a "modest amount" of the damages), COL 2 (describing uncertainty of litigation and associated expense)

[363] Ex. DRA-1 at p. 4-8, lines 17-22.

in monthly payments.[364] ORA recommends a further disallowance for Wendel related to the net present value of the repayments over time.[365] PG&E asserts that a disallowance is not warranted but, if it is, the appropriate discount rate is 7%, not the 7.6% used by ORA.[366] It is undisputed that since January 1, 2013, PG&E has been using a 7% discount rate. Since the vast majority of the repayments from Wendel will occur after January 1, 2013, it is appropriate to use the current discount rate to determine the net present value of the repayments. Given the fact that very few of the Wendel repayments occurred before January 1, 2013, it is not appropriate to use the 7.65% discount rate advocated by ORA. PG&E provided the net present value of the Wendel repayment in its discovery response marked as Exhibit PG&E-11-C.[367]

C. The UCSF Settlement Is Reasonable and Prudent

The third transaction addressed in ORA's testimony concerns an agreement between UCSF and PG&E. PG&E and UCSF entered into a QF PPA in 1997. Due to the size of UCSF's load and constraints on the PG&E distribution system, the campus is served by two separate 12 kV feeders, with a third as a backup; each of the three feeders has its own bi-directional meter.[368] None of the existing PG&E feeders to the UCSF campus can carry the full campus load. When the cogeneration plant is at full operation, there are times when the campus is drawing power from the PG&E grid on one feeder, while simultaneously putting power into the PG&E grid on the other feeder.

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[364] Ex. PG&E-1-C at p. 10-34, lines 5-10 (explaining Wendel repayment); Ex. 11-C (Response to DRA Data Request Set #2, Question 2, Item 2.3.2.4.1) (describing period of time over which monthly repayments will be made).

[365] Ex. DRA-1-C at p. 4-10, lines 1-15.

[366] Ex. PG&E-3 at p. 5-4, line 27 to p. 5-5, line 5.

[367] Ex. PG&E-11-C (Response to DRA Data Request Set #2, Question 2, Item 2.3.2.4).

[368] Ex. PG&E-1 at p. 10-34, lines 15-24 (describing UCSF configuration).

In December 1999, PG&E and UCSF agreed to provide service as if there was only one meter serving the entire campus, and signed a "totalization agreement."[369] The totalization process uses an algorithm applied to the meter data to create a data stream reflecting UCSF's net usage and generation. On January 1, 2003 UCSF began to regularly deliver energy to PG&E, but QF settlements personnel only received meter data for one of the three meters, and no totalization algorithm was applied to the data. PG&E discovered the error in 2011.

On October 29, 2012, PG&E and UCSF executed a Settlement Agreement and Full and Final Release (which has been identified as Exhibit PG&E-15) to adjust payments to UCSF back to January 1, 2003 using the corrected meter data, and in October 2012 PG&E made a $1,151,094.88 true-up payment to UCSF.[370] PG&E's payments simply compensated UCSF for energy that was delivered and used by PG&E's customers, but which was not included in the meter reads as a result of the algorithm not being properly set up. PG&E did not pay any interest on the amount owed to UCSF for the energy that UCSF provided to PG&E's customers.

ORA has not recommended any disallowance related to the UCSF settlement because, as ORA witness Colin Rizzo explained during the hearing, "ratepayers were not adversely impacted."[371] Under the settlement, PG&E simply paid "for what was due"[372] and because there was no interest associated with the settlement, ORA's witness acknowledged that there was no customer harm.[373] The settlement was reasonable because it simply provided for payment to UCSF of amounts customers would have paid in prior years, but were not required to do so because of the algorithm error. PG&E acted reasonably and prudently by negotiating a

[369] Ex. PG&E-1 at p. 10-34, lines 25-32 (describing totalization agreement); Ex. PG&E-3 at p. 5-5, lines 13-19 (describing UCSF metering algorithm).

[370] Ex. PG&E-1 at p. 10-34, line 32 to p. 10-35, line 2.

[371] Tr. at p. 360, lines 5-6 (ORA, Rizzo).

[372] Tr. at p. 360, line 15 (ORA, Rizzo).

[373] Tr. at p. 361, lines 4-23 (ORA, Rizzo).

settlement that did not include interest or payment of any amount above and beyond what customers would have paid anyway.

Although ORA does not recommend a disallowance, it has recommended certain corrective actions.[374] Specifically, DRA has recommended a "contract audit" every three years that would "focus on whether PG&E is complying with its contractual obligations, prudently administering its contracts, and dispatching energy at the lowest possible cost for ratepayers."[375] There are several problems with ORA's proposal. First, ORA's proposed contract audit has nothing to do with the UCSF situation.[376] UCSF involved a problem with a metering algorithm that would not have been discovered during the "contract audit" that ORA proposes.

Second, ORA's proposal is vague, broad, and open-ended.[377] ORA's testimony does not describe the scope of the audit, what would be included, or the actual activities that would be audited. In discovery, PG&E sought further clarification from ORA regarding its proposed corrective action. However, ORA's data responses were equally as vague and lacking in details. Rather than explain the scope of its proposed audit, ORA simply stated that the auditors will decide at some future point in time.[378] The Commission should not adopt a proposal for an audit that is vague as to scope and completely open-ended. This lack of clarity in ORA's proposal will likely result in future disputes down the road that the parties and/or the Commission will need to resolve.

Finally, ORA fails to provide any evidence or argument that its proposed corrective actions will produce any benefit for customers. In this proceeding, ORA only identified three

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[374] Ex. DRA-1 at p. 4-4, line 5 to p. 4-5, line 2 (describing proposed corrective actions).

[375] Ex. DRA-1 at p. 4-4, lines 8-10.

[376] Ex. PG&E-3 at p. 5-6, lines 17-23.

[377] Ex. PG&E-3 at p. 5-6, line 28 to p. 5-7, line 19.

[378] Ex. PG&E-3 at p. 5-7, lines 8-19.

situations of concern out of the hundreds of contracts that were administered by PG&E during the record period. Given the lack of substantive problems identified by ORA, the cost and time necessary to perform the open-ended audit proposed by ORA is not justified. This point is made all the more clear by the fact that the audit proposed by ORA would not have addressed any of the three situations of concern identified in ORA's testimony.[379] In short, ORA has proposed a solution which does not address a problem. ORA's proposed corrective actions are unnecessary, costly, and will likely result in few benefits, and thus its proposal should be denied.

XII. CAISO SETTLEMENTS AND MONITORING (EXHIBIT PG&E-1, CHAPTER 11)

The CAISO imposes charges and costs on Scheduling Coordinators ("SCs") that schedule generation and/or load into the CAISO markets, and also pass-through revenues for generation scheduled into the market.[380] During the record period, PG&E acted as an SC for its bundled customers, scheduling both load and generation on their behalf. The net expense incurred by PG&E for its participation in the CAISO markets was $610,180,512.[381] In PG&E's Prepared Testimony it described the various elements of this net expense and explained its validation and settlement process to ensure that the CAISO-imposed costs are appropriate.[382] CAISO revenues and costs are included in PG&E's ERRA balancing account and are summarized in PG&E's Prepared Testimony.[383] ORA's testimony did not raise any concerns about CAISO settlements or monitoring.[384] PG&E is not requesting a specific finding regarding CAISO settlements and

[379] Ex. PG&E-3 at p. 5-6, lines 17-23.

[380] Ex. PG&E-1 at p. 11-1, lines 5-16.

[381] Ex. PG&E-1 at p. 11-1, lines 18-19.

[382] Ex. PG&E-1 at p. 11-1, line 22 to p. 11-4, line 13.

[383] Ex. PG&E-1 at p. 13-1, line 22 (CAISO charges included in ERRA balancing account); *see also e.g.* p. 13-11, Table 13-2, lines 5.t (spot market purchases from CAISO market), 5.z (revenues from Congestion Revenue Rights).

[384] Ex. DRA-1 (Memorandum) at p. 2 (DR contract administration not covered in ORA's testimony).

monitoring during the record period, but provided this information as one element of the costs and revenues included in the ERRA balancing account.

XIII. DEMAND RESPONSE CONTRACT ADMINISTRATION (EXHIBIT PG&E-1, CHAPTER 12)

The majority of PG&E's Commission-approved demand response or "DR" programs are not reviewed in this proceeding and the costs associated with these programs are recovered through the Distribution Revenue Adjustment Mechanism ("DRAM"), which is not at issue in this proceeding.[385] Moreover, most of the DR Programs cannot be bid into the CAISO markets and thus do not implicate LCD.[386] PG&E did include in its Prepared Testimony a discussion of the costs associated with the Aggregator Managed Portfolio ("AMP") program because these costs are recovered through ERRA. During the record period, PG&E administered four (4) Commission-approved AMP contracts.[387] PG&E's Prepared Testimony explained the tools and internal controls that were used to administer and settlement these contracts, PG&E's compliance monitoring, and the AMP three events that were called in 2012 consistent with the AMP contract terms.[388] PG&E's Prepared Testimony also included a breakdown of the monthly cost for the four AMP contracts during the record period.[389] ORA's testimony did not raise any concerns about PG&E's administration of the AMP contracts.[390]

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[385] *See e.g.* D.12-04-045 at pp. 166-167 (describing process for review and evaluation of DR programs).

[386] Tr. at p. 58, line 1 to p. 59, line 4 (PG&E, Svoboda).

[387] *See* D.12-04-045 at pp. 73-76 (approving 2012 AMP contracts); Ex. PG&E-1 at pp. 12-1 to 12-2 (describing the five AMP contracts). PG&E's testimony identifies the five (5) original AMP contracts. However, Constellation New Energy decided not to extend its AMP contract and thus this contract expired on December 31, 2011, before the record period at issue in this proceeding. *See* Ex. PG&E-1 at p. 12-2, lines 1-5.

[388] Ex. PG&E-1 at p. 12-2, line 25 to p. 12-6, line 6.

[389] Ex. PG&E-1 at p. 12-6, Table 12-1.

[390] Ex. DRA-1 (Memorandum) at p. 2 (DR contract administration not covered in ORA's testimony).

XIV. ERRA BALANCING ACCOUNT ENTRIES (EXHIBIT PG&E-1, CHAPTER 13)

In its Prepared Testimony and workpapers, PG&E provided a monthly breakdown on each line item in the ERRA balancing account and the revenues and costs associated with each item. PG&E also described tariff changes, advice letters and significant events that impacted the ERRA balancing account.[391] ORA performed an extensive audit of PG&E's ERRA balancing account entries for the record period, including reviews of testimony and workpapers, analysis of monthly entries, and selection and examination of certain sample entries, including invoice, journals and general ledger entries.[392] After this extensive audit and review, ORA "did not note any items of a material nature requiring adjustments to PG&E's ERRA" and "noted no exceptions to the recovery requirements adopted by the Commission for this account."[393] Indeed, ORA's witness Grant Novack testified at the January 21st hearing:

> Q So you're confident based on your experience as an auditor that you would catch things like that by following the processes that you --
>
> A Well, it's not 100 percent. But I do find -- sometimes I find like minor exceptions like maybe some sort of timing difference or something because there are accruals from month to month. And there's, you know, adjustments that are made over each month. But I find that -- <u>And especially I have to be complimentary of PG&E. I think they do a tremendous job on their -- at this point up to now on their recording of costs and expenses and revenues in their ERRA balancing account. They're very good</u>. They identify each line item -- I mean, each tariff description item, which may not be the case with other utilities or which may have been an issue at one time. And they're able to provide supporting documentation when I request it for their monthly entries, so.[394]

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[391] Ex. PG&E-1 at p. 13-3 to p. 13-10.

[392] Ex. DRA-1 at p. 8-1, line 16 to p. 8-2, line 6.

[393] Ex. DRA-1 at p. 8-3, lines 2-4.

[394] Tr. at p. 508, line 22 to p. 509, line 16 (ORA, Novak) (emphasis added).

XV. CAISO MARKET DESIGN INITIATIVE EXPENSES (EXHIBIT PG&E-1, CHAPTER 14)

During the record period, PG&E continued to incur capital and expense costs related to CAISO Market Design Initiatives that were included in a series of initiatives after the initial release of the CAISO's MRTU.[395] These initiatives are mandated by regulatory and reliability requirements of the CAISO and FERC. PG&E incurs necessary, incremental Information Technology ("IT") capital and expense expenditures that are required to upgrade systems so that PG&E can participate in the CAISO markets.[396] In 2013, PG&E incurred $3.58 million in capital expenditures and $64,000 in incremental expenses associated with the CAISO Market Initiatives. PG&E seeks recovery of these amounts in this proceeding.

FERC approved the CAISO's initial MRTU in 2006. Since that initial approval the CAISO's market redesign has become an ongoing, multi-year process. The CAISO has undertaken additional changes by implementing new market design initiatives through periodic Releases to enhance and further refine the system.[397] In order to capture the costs associated with these required ongoing CAISO system changes, Commission Resolution E-4093 authorized PG&E to establish the Market Redesign and Technology Upgrade Memorandum Account ("MRTUMA") to record its incremental costs associated with the CAISO's Market Design Initiatives. In that Resolution, the Commission explained that "[t]he IOUs should be prepared with the necessary resources, tools, computer software and hardware to be able to implement MRTU Release 1, currently scheduled for February 2008, and all subsequent Releases."[398] Since the effective date of the MRTUMA, PG&E has recorded incremental costs associated with CAISO Market Design Initiatives that became operational from 2009 through 2011 and

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[395] Ex. PG&E-1 at p. 14-1, lines 6-20.

[396] *Id*. at p. 14-1, lines 21-25.

[397] *Id*. at p. 14-2, lines 2-6.

[398] Resolution E-4093 at p. 5.

presented those to the Commission for approval in Applications 10-02-012,[399] 12-01-014 and 12-04-009.[400] In addition, pursuant to Resolution E-4093, PG&E has periodically informed the CPUC's Energy Division of its estimated incremental costs related to major CAISO releases prior to recording those costs in the memorandum account.

In this proceeding, PG&E provided detailed testimony demonstrating that the expenditures incurred during the 2013 record period were reasonable, verifiable, and incremental to the costs recovered in other proceedings. With regard to reasonableness, PG&E described in detail its approach to implementing CAISO Market Design Initiatives and then described each project for which PG&E seeks recovery.[401] All of these projects were the direct result of CAISO Market Design Initiatives and facilitated PG&E's participation in the CAISO markets on behalf of its customers. PG&E also demonstrated reasonableness by reviewing its labor costs, hardware and software costs, overheads, and expenses.[402] In addition to the issue of reasonableness, PG&E also provided testimony demonstrating that the costs were verifiable (*i.e.*, were included in the MRTUMA) and were incremental (*i.e.*, were not recovered in any other proceeding).[403] After a careful review, ORA concluded that there were no "items of materials nature requiring adjustments" to the costs recorded by PG&E in the MRTUMA.[404] Based on the record in this

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[399] The Commission issued Decision 11-07-039 authorizing PG&E to recover $18.3 million MRTU revenue requirements recorded in the MRTUMA (A.10-02-012), subject to an audit by the CPUC. On November 28, 2012, the CPUC auditor issued its report identifying no non-compliance instances and found that the costs recorded in the MRTUMA were incremental and reasonable, and confirmed that all funds were spent on MRTU projects. (Attestation Audit of PG&E's Market Redesign and Technology Upgrade Memorandum Account for Calendar Years 2007, 2008 & 2009 by Macias Consulting Group, Inc.)

[400] The approval of PG&E's recorded incremental costs from Applications 12-01-014 and 12-04-009 is still pending at the Commission.

[401] Ex. PG&E-1 at pp. 14-3 to 14-19.

[402] Ex. PG&E-1 at p. 14-19, line 22 to p. 14-21, line 29.

[403] Ex. PG&E-1 at p. 15-1, line 25 to p. 15-2, line 1 (verifiable) and p. 15-, line 1 to p. 15-4, line 30 (incremental).

[404] Ex. DRA-1 at p. 7-3, lines 3-8.

proceeding, the Commission should approve the $3.58 million in capital expenditures and $64,000 in incremental expenses incurred by PG&E associated with the CAISO Market Initiatives.

XVI. COST RECOVERY AND REVENUE REQUIREMENTS (EXHIBIT PG&E-1, CHAPTER 15)

Most of the issues in ERRA compliance proceedings do not involve cost recovery or revenue requirements. However, because the CAISO Market Design Initiatives and Diablo Canyon seismic studies involve costs and expenditures, PG&E included a specific cost recovery and revenue requirement proposal for these aspects of its application. PG&E's testimony demonstrated the reasonableness of its revenue requirement and cost recovery proposal by summarizing the expenses, described the revenue requirement methodology, and explained the Results of Operations calculations and cost recovery process.[405] ORA did not address PG&E's cost recovery and revenue requirement proposal in its testimony. Based on the undisputed evidence, the Commission should approve PG&E's cost recovery and revenue requirement proposal.

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[405] Ex. PG&E-1 at pp. 15-1 to 15-12.

XVII. CONCLUSION

Based on the above discussion of the facts in this proceeding and Commission precedent, PG&E respectfully requests that the Commission adopt the recommendations made by PG&E at the beginning of this Opening Brief. These recommendations are fully supported by the record in this proceeding and Commission precedent, as described in detail in this Opening Brief.

Respectfully submitted,

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